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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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COVER: *(Page 23) | Northern Indiana Public Service Co.*

RTO Insider LLC
2415 Boston St.
Baltimore, MD 21224
(301) 658-6885

In this week's issue

Counterflow

By Steve Huntoon

Back to the Future

By Steve Huntoon

It seems like yesterday I started scribbling about all manner of industry subjects — against the flow, the prevailing wisdom, the latest hype, etc.

But it's actually been 10 years. With that passage of time, spanning 90 columns and articles all *available here*, I thought I'd look back at what I might have gotten right, gotten wrong or whatever. And what such might portend for the next 10 years.

Let's start with — who else — Elon Musk and his claims for his new home battery, *the Powerwall*. Including pairing with his cousins' SolarCity's solar panels. Powerwall and SolarCity didn't live up to Musk's early hype, as *I discussed* in *follow-up* columns (*one more*), but they finally became a profitable part of Tesla. Maybe I should get partial credit.

Next subject was *Big Transmission* (not to be confused with economic interregional ties). Back then, I summarized the prior 10 years: "It was heady stuff: Big lines and arrows sweeping across the country, depicting massive new transmission projects. But after 10 years of dramatic announcements and proposals, the reality today is that Big Transmission has fallen and it won't be getting up. And a second reality is this: The fall of Big Transmission is not a public policy failure. Rather, Big Transmission never did make sense. Instead, the experience so far points to a continuation of what we're doing now — to more of the incremental transmission expansions that have characterized the past 10 years — and not to count on Big Transmission as a solution to any future industry challenge." Another 10 years and the song remains the same. ☑

On to *microgrids*! I showed that microgrids are the irrational antithesis of everything we know about electric system planning and operation. A couple years later, *I discussed* the threat microgrids posed to national security, did *a recap* a couple years later, and then this year *covered* the microgrid boondoggle in Chicago. ☑

Tesla Powerwall batteries | *Shutterstock*

Next up were *utility-scale batteries*. I showed that the two claimed value propositions, capacity backup and energy arbitrage, didn't pencil out. Battery costs have since come down significantly, but batteries remain a niche product absent subsidies and/or mandates. Hmm, maybe another partial credit.

On to *New York's REV* ("Reforming the Energy Vision"). As I said back then, it was the most hyped regulatory initiative since the California restructuring some 20 years prior. REV was mostly word salad, but one of the few specifics was subsidizing utilities to install rooftop solar. I couldn't imagine a worse idea. ☑

Well, except maybe California's artificial creation of *the Duck Curve* by layering one bad policy on top of another. Free storage and distribution in the form of net metering, uneconomic time-of-use rates discouraging afternoon usage, subsidies of battery storage reducing afternoon usage. Yikes. Many years later, the Duck is finally getting targeted, but not before helping drive California's electric rates to astronomical levels. ☑

Another close contender from California was *the planned closure* of the Diablo Canyon nuclear plant. Perhaps my hair-on-fire column helped save the plant … and perhaps helped the planet. ☑

Oh, and lest we forget Bernie Sanders' promise to *ban fracking* during his 2016 campaign. Not only to cost consumers some $100 billion annually, but to increase carbon emissions by increasing coal-fired generation. Yikes! ☑

Enough reminiscing for one day!

P.S. Except to add to prior columns' postscripts about Peace, Love and Understanding. Here's an audio version by the guy who wrote it, *Nick Lowe*. Oh, and *this cover* by Elvis Costello 20 years ago is epic.

As Spinal Tap said: Turn it up to 11. ■

Columnist Steve Huntoon, principal of Energy Counsel LLP and a former president of the Energy Bar Association, has been practicing energy law for more than 30 years.

FERC/Federal News

ACEG Report Lays out Best Practices for States to Build Transmission

By James Downing

Americans for a Clean Energy Grid (ACEG) released a report Sept. 9 highlighting the critical role states can play in modernizing and expanding the grid.

FERC has jurisdiction over interstate transmission, but states play a crucial role in comprehensive and cost-effective transmission planning and development. The report is meant to inform state policymakers and advocates by offering examples of impactful policies, and it emphasizes the importance of interstate collaboration.

The report is based on surveys and a series of interviews with transmission experts, including advocates, utility staff, developers and state legislators.

"As they look to unlock economic development and support affordable energy for their communities, states can play a significant role in supporting transmission and collaborating with their neighbors in order to develop a better grid," ACEG Executive Director Christina Hayes said in a statement. "The policies highlighted in this report offer a road map for states looking to lead on this critical issue."

The report, "State Policies to Advance Transmission Modernization and Expansion," noted that no policy panacea exists for states because of their differences, but it suggests supporting the principles of reliability, resilience and affordability. Coordination among all levels of government is important, including within the state, with other jurisdictions and in the regional planning process, along with other interested parties.

States should promote comprehensive and coordinated regional and interregional grid planning that fully considers transmission modernization technologies and transmission expansion options, with longer time horizons, to pick the most cost-effective solutions, ACEG said.

The report also calls on states to facilitate robust and streamlined processes for siting transmission, with early and meaningful engagement opportunities and support for impacted communities.

Some policies can become barriers for transmission development, with the report saying short-term plans do not work well for transmission infrastructure, which can have a lifespan of at least 50 years.

Some planning can fail to account for the benefits provided by an interconnected network, siloing the state so regulators consider only whether electrons are delivered within it. Or they can seek to protect in-state resources at the expense of reliability and customers.

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"Notwithstanding the potential for state policies to erect barriers, experts surveyed for this report were excited about the opportunities for increased state engagement on transmission," the report said. "They encouraged states to [not only] improve ... their own state policies, but [also] to collaborate with neighboring and other electrically interconnected states to adopt similar policies to amplify the impact on regional and interregional planning and development."

On siting and permitting, the report suggests minimizing duplication between a state's own process and those of the federal government, the region and its individual neighbors. States should maximize the use of existing rights of way, including siting lines alongside train tracks and highways.

When it comes to costs of transmission, the report encourages states to participate in regional and interregional cost allocation discussions. It also suggested using public funding for some lines to minimize consumer bill impacts.

In addition to simply expanding the grid, modernization and the adoption of grid-enhancing technologies (GETs) also is important. The report suggests directing utilities to study GETs and high-performance conductors and, when legally sustainable, to offer such projects incentives.

States could create environments that favor advanced transmission technologies, with the report suggesting states exempt them from permitting requirements or set operational standards that encourage their use.

The report brings up state right-of-first-refusal laws, but it does not take a firm position on them. It notes that proponents believe ROFRs encourage more collaborative planning by utilities and cut the time to competitively bid transmission, but opponents argue that competition encourages innovation and cost effectiveness.

"This report underscores the critical role that states play in modernizing and expanding our nation's transmission infrastructure," AEU Managing Director Jeremy McDiarmid said in a statement. "As the backbone of our electric grid, transmission ensures that electricity remains affordable, reliable and resilient. This means states must work together in collaborative transmission planning." ■

Webinar Examines How FERC Could Use Interregional Transfer Study

By James Downing

Congress and FERC will need to act to update the rules on interregional transmission planning, and likely permitting, if NERC's Interregional Transfer Capability Study is going to be of any use, experts said on a webinar hosted by Americans for a Clean Energy Grid.

The study is only the second thing Congress has ever requested from NERC, after it called for the creation of the Electric Reliability Organization in the Energy Policy Act of 2005, said John Moura, director of reliability assessment and system analysis. NERC recently released its initial results, but the final report is not due to FERC until Dec. 2. (See *NERC Examines Transfer Capability in Draft ITCS Installment*.)

"The ITCS is really an unprecedented study, both in scale and magnitude of what we have to look at," Moura said. "It's a U.S.- and Canada-wide technical assessment that looks at the power transfers between regions, and then also makes recommendations to increase those transfers based on reliability needs."

Once FERC gets the report in December, it will open it up for comments, which will put it before a much larger group of stakeholders, Moura said. Though Congress directed the study, Canadian representatives wanted their own version, which will be published in the first quarter of 2025, he added.

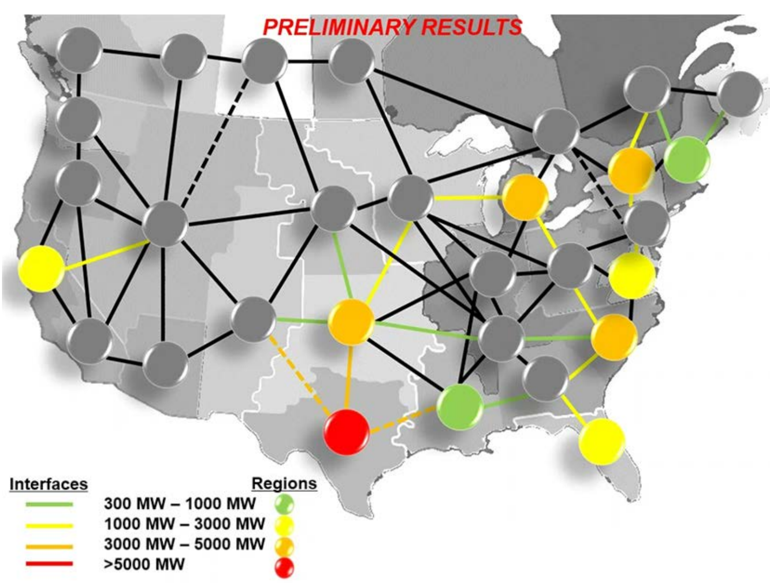
NERC found greater needs for transfer capabilities in some regions compared to others, with Moura presenting a color-coded slide with green, yellow and red for increasing regional needs. While the red and orange areas would benefit from more transfer capacity, Moura noted that the green and gray regions still require work to maintain reliability.

The study assigned "prudent" transfer capability between regions, which means how much is required to meet load under extreme conditions, Moura said.

In doing the study, NERC had to use the same metrics for different regions, which is not how it operates in its own regional planning efforts, so it could accurately assess transfer capabilities. One key finding of the studies is that increasing interregional transfer capability is not enough to ensure reliability.

"I think the results are pretty clear: Adding transfer capability to a minimum level is not sufficient in resolving reliability issues for some areas," Moura said. "And for other areas, adding transfer capability where it's not needed would not appear to be economically prudent, without much benefit to reliability. Also, transmission is only one option and only one solution."

Transfer capability can help with reliability issues in some regions, but so can adding new generation — especially types that are not subject to the same common mode failures plaguing generator availability, Moura said. Higher transfer capabilities will require significant planning and systemwide reinforcements, he added.



The preliminary results of NERC's ITCS study show where it would make the most sense to build interregional transmission capacity. | *NERC*

Nicole Luckey, Invenergy senior vice president of regulatory affairs, said the current rules are not working.

"There are no holistic interregional transmission planning or cost allocation processes in place today, aside from what was laid out in Order 1000, which I think we all can acknowledge isn't necessarily working now," Luckey said. "We're all really looking forward to the folks in the transmission development community seeing what FERC does with NERC's study."

One question is whether the commission will stick to purely reliability benefits or consider others in that effort, she added.

American Electric Power owns utilities in four different ISOs and RTOs, and many of its territories are located along market seams, so it has had a front-row seat to view how Order 1000's interregional process has failed, said Stacey Burbure, vice president for FERC and RTO strategy. A key reason is that different regions consider transmission with different metrics.

"When you're comparing apples and oranges, it's not always intuitive what the right solution is, which is why coordination simply hasn't gotten us there," Burbure said. "The RTOs are on different timelines. They're looking at different inputs. So, moving towards a more standardized approach, with respect to that engineering information, is going to be critical in order to get the right transmission built."

FERC should take steps with interregional transmission like it did in Order 1920 with regional planning, so the different regions are examining interregional lines on the same basis, she added.

Brattle Group Manager Joe DeLosa agreed that FERC would need to get more common metrics in place to make interregional planning successful, but he also noted that planners currently use models of the system in normal conditions.

The National Renewable Energy Laboratory "has recently said that about half of the benefits of interregional transmission come from the most stressed 5% of system hours," DeLosa said. "And so, if your interregional coordination/planning, especially for economics, doesn't take a look at those hours, you're going to be overlooking large portion of potential interregional benefits, and you're not ultimately going to develop the appropriate projects." ■

USDA Program Offers $7.3B to 16 Rural Cooperatives

By Tom Kleckner

The U.S. Department of Agriculture on Sept. 5 *announced* more than $7.3 billion in financing for 16 cooperatives as part of its largest investment in rural electrification since 1936.

The department released the grants under its Empowering Rural America (New ERA) program. The $9.7 billion program is part of the Inflation Reduction Act and designed for cooperatives interested in buying or building new energy systems.

National Rural Electric Cooperative Association CEO Jim Matheson welcomed the news, calling it a "transformative opportunity" for cooperatives.

"The New ERA program showcases what is possible when the government prioritizes voluntary, flexible decision-making and allows electric co-ops to take a tailored approach to respond to local needs," he said in a *statement*.

All but one of the *16 cooperatives* have completed the New ERA's competitive stage and are in the underwriting process to receive an award. They include three co-ops from Colorado: Tri-State Generation and Transmission Association ($679 million), United Power ($261 million) and CORE Electric Cooperative ($225 million).

Tri-State, which provides wholesale power to its 41 members, plans to use the funds to build or buy 1,480 MW of solar, wind and battery storage and to support the retirement of 1,100 MW of coal-fired generation. It said that will eliminate nearly 5.8 million tons of greenhouse gas emissions annually.

Texas' San Miguel Electric Cooperative said that if it is awarded New ERA funds, they will be used to convert the co-op's lignite operations to 400 MW of solar generation and build a 200-MW battery storage facility. It also could use the funding to refinance debt from its stranded lignite infrastructure, a significant obstacle for the transition to solar generation, it said. San Miguel's 410-MW coal plant is among the *top 30 facilities* in emitting mercury.

USDA received more than 160 requests for more than $44 billion in funding. Its first New ERA award ($573 million) went to Wisconsin's Dairyland Power Cooperative, which plans to procure 1,080 MW of renewable energy through four solar installations and four wind farms across Wisconsin, Iowa, Minnesota and Illinois. ■

| *Tri-State G&T*

FERC/Federal News

AEU Webinar Highlights Potential Queue Improvements

Event Comes Week Before FERC Technical Conference

By James Downing

Speeding up the interconnection queues is becoming more important as demand growth and the retirement of existing generators combine to cut into reserve margins around the U.S., experts said during a webinar Sept. 4 hosted by Advanced Energy United.

Grid Strategies President Rob Gramlich summarized a recent *report* his firm co-authored with the Brattle Group for United and the Solar and Storage Industries Institute called "Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid."

The report's recommendations would help developers of generation get more certainty from the interconnection process, which generators do not have when they enter the queues and put up deposits to save a place in line, Gramlich argued.

"The developers really need certainty, or else, if you don't have it, you'll continue to have this queue churn and projects coming in and out in order to get information," Gramlich said.

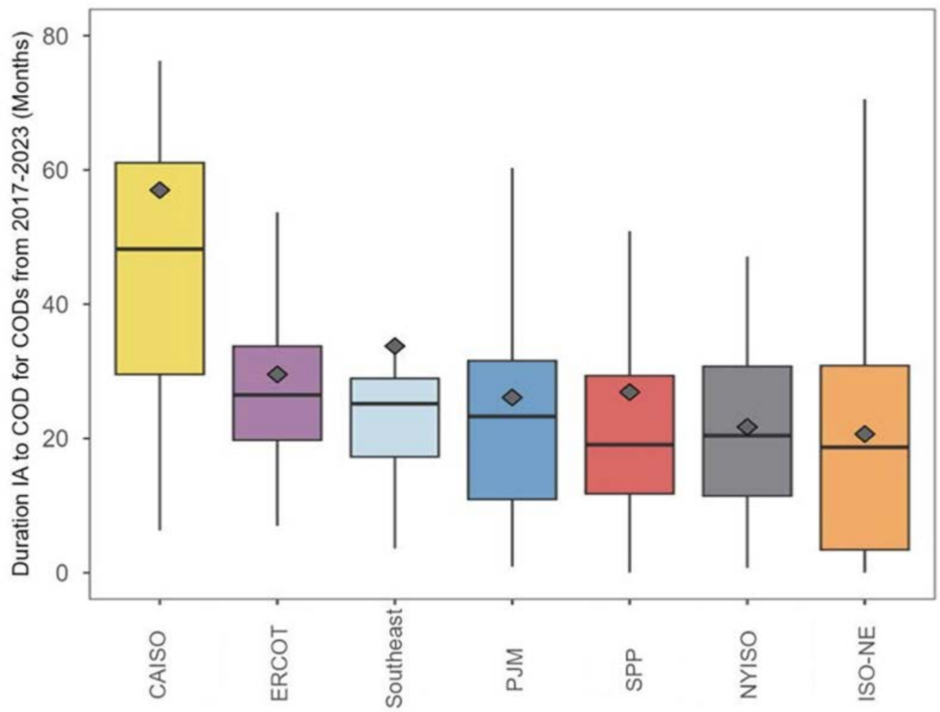
After putting up their deposits, projects end up in a study process that is usually lengthy; then getting them built can be delayed because of required transmission upgrades, Gramlich said.

Supply chain issues are delaying both the construction of network upgrades and sometimes the generators themselves, with PJM reporting that nearly 40 GW of projects have made it through its queue but are not in operation yet.

"There's no single answer to that, but there's maybe a few common challenges," said Hannah Muller, senior director of external and market affairs at Clearway Energy Group. "One is supply chain; that's both for the actual project equipment, but also the transmission infrastructure. There's just years [of] delay in getting necessary equipment; it's just a function of the global economy at this point."

Other issues include permitting and community opposition to new infrastructure; FERC and the RTOs can speed up the interconnection, but those are outside of their purview, Muller said.

FERC made changes to the baseline for queues with Order 2023, but the report and panelists argued that additional measures are needed. The commission is holding a two-day technical conference from Sept. 10 to 11 on that subject; Gramlich said it would be a good venue for helping to share best practices from the different regions.



A chart from Berkeley Lab showing how long it can take to build interconnection upgrades by grid operator, based on available data, which Grid Strategies and Brattle Group used in their report | *Lawrence Berkeley National Lab*

In addition to certainty, the Grid Strategies report argues for quicker schedules and non-discrimination that guarantees a level playing field for "similarly situated interconnection customers." Adopting an interconnection entry fee for proactively planned capacity would provide customers with significant interconnection cost certainty and address cost allocation of the upgrades identified. The report also suggests a fast-track process to use existing and already-planned interconnection capacity that would prioritize the projects most ready to go live.

The interconnection study process also needs improvements to enable the fast-track process and make studies more efficient generally, the report said.

One promising way to improve the study process that is in its early stages is the use of artificial intelligence, said Kyle Davis, the Clean Energy Buyers Association's senior director of federal affairs.

"SPP, Amazon Web Services, Pearl Street [Technologies] and NextEra [Energy] are testing out Pearl Street's SUGAR platform to try and help organize and bring that machine-learning process to the interconnection queue analysis," Davis said.

Testing so far indicates the technology can whittle what has historically taken three months down to as little as an hour, he added. The report discusses the pilot effort, and Pearl Street's CEO, David Bromberg, is a *witness* at FERC's technical conference next week.

The final set of modifications that the report suggests is around speeding up the transmission construction backlog to address growing constraints that hinder network upgrades. The report noted that while it did not focus on proactive transmission planning, that is key to speeding up the queues, and several transmission providers are already implementing proactive planning, while others are developing long-term planning processes to comply

FERC/Federal News

with FERC Order 1920.

Speeding up construction also would mean addressing supply chain issues, with which the Department of Energy could help, Gramlich said. As for FERC jurisdictional issues, it is unclear why some utilities can get network upgrades built more quickly than others; the report suggests some independent monitoring of that stage to identify why that is happening and address issues that slow down construction, Gramlich added.

Demand is growing, but supply is out there that could address it, said R Street Institute Senior Fellow Beth Garza, who is also *speaking* at FERC's technical conference next week.

"Those costs eventually are borne by consumers," Garza said. "It's consumers that are using the electricity. They're the ones getting value out of having the electricity. ... It's the indirect costs that consumers absolutely bear by inefficient processes." ■

FERC/Federal News

DOE Approves 1st LNG Exports Since Biden Administration's Pause

By James Downing

The Department of Energy on Aug. 31 *approved* a five-year term for New Fortress Energy's Fast LNG 1 project to export gas produced in the U.S. to countries without free trade agreements (FTAs).

The LNG facility recently started operations in Altamira, Mexico, and will receive U.S.-produced gas via pipeline to export. It announced its first exports in August, having already won approval to ship gas to countries with FTAs.

The authorization comes after a court stayed the Biden administration's pause on such approvals, announced earlier this year, and while DOE works on a related study on the environmental impacts of LNG exports. (See *Federal Judge Stays Biden's LNG Export Application Pause*.)

"This important authorization cements NFE's position as a leading global vertically integrated gas to power company and enhances the marketability of our FLNG 1 asset," CEO Wes Edens said in a statement Sept. 3. "NFE is now able to freely supply cheaper and cleaner natural gas to underserved markets across the world and further our goal of accelerating the world's energy transition."

DOE approved the facility to ship 145 Bcf/year of U.S.-produced LNG. The gas will flow into Mexico over the Valley Crossing Pipeline, which runs south from Texas, and potentially other cross-border pipelines that have yet to be completed.

The exports to non-FTA countries give NFE more flexibility with the facility, DOE said.

"These re-exports can diversify global LNG supplies and improve energy security for U.S. allies and trading partners," the department said. "Based on this administrative record, DOE has determined that it has not been shown that NFE Altamira-proposed re-exports of LNG to non-FTA countries will be inconsistent with the public interest over the authorization period."

DOE's approval is in effect for five years, until Aug. 30, 2029, but NFE wants to keep exporting gas until 2050. The department will reevaluate its approval once the company formally asks for a new end date.

So far, DOE has approved 46.45 Bcfd of natural gas exports, which includes 6.71 Bcfd of gas shipped to Canada and Mexico before being exported overseas.

North America's export capacity is on pace to double by 2028, from 11.4 Bcfd to 24.4 Bcfd, the Energy Information Administration *said* Sept. 3.

The U.S. is home to 9.7 Bcfd of projects under construction, with Canada building 2.5 Bcfd and Mexico 0.8 Bcfd. The Canadian facilities would export gas produced there, but the Mexican facilities are seeking to export gas initially produced in the U.S.

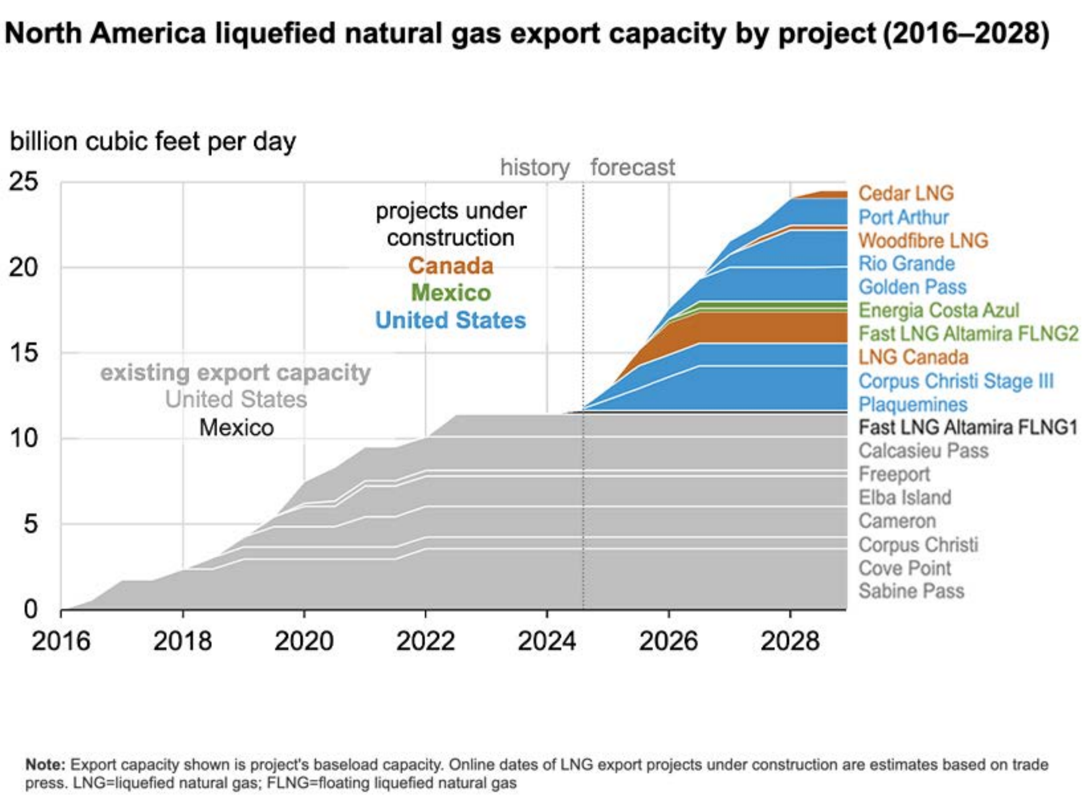
In approving NFE's application, DOE said it would monitor market developments closely as the impact of successive authorizations of LNG exports continues to unfold.

"DOE also acknowledges that proposals to re-export U.S.-sourced natural gas in the form of LNG from Mexico or Canada to non-FTA countries raise public interest considerations that are not present for domestic exports of LNG," DOE said. "In the case of re-exports, the U.S. economy does not receive a significant portion of the benefits DOE has recognized for LNG exported directly from the United States, particularly with respect to the jobs and infrastructure investment associated with construction and operation of liquefaction facilities."

Foreign LNG export facilities are also not subject to U.S. environmental laws, which could lead to long-term issues if local laws are laxer, DOE added.

The export application was opposed by environmentalists, with Sierra Club protesting and Food & Water Watch releasing a statement blasting the approval.

"It's ridiculous that the Department of Energy would issue this license despite the administration's ongoing, incomplete public interest review of such exports," said Mitch Jones, managing director of advocacy and policy. "The department is under no obligation to approve these ill-advised proposals, now or ever. As the disastrous impacts of increased fossil fuel development become more and more obvious here and around the globe, the notion of expanded LNG exports should be dismissed out of hand." ■



| *EIA*

FERC/Federal News

Study: HVDC Needs Standards to Take off in US

DNV Working on Developing Standards for HVDC in Effort Expanding to Include DOE

By James Downing

HVDC transmission lines can help efficiently connect offshore wind power, meet growing demand onshore and link together the balkanized grid, but before their use can be expanded in the U.S., the OSW industry to needs to set some standards, according to a joint company survey.

DNV's HVDC Standards joint industry project (JIP), which finished its first phase in April, was convened to identify deficiencies in standards for HVDC. DNV worked with Atlantic Shores Offshore Wind, EDF Renewables, Equinor, Invenergy, National Grid Ventures, Ocean Winds, PPL TransLink, WindGrid, RWE, Shell and TotalEnergies.

The firm launches JIPs when a need crops up in the industries it covers for firms to come together and work on a common issue. While HVDC lines have been growing in the U.S., the domestic industry and regulators still lack key standards to deal with how the technology impacts the grid, DNV Principal Consultant Morgan Putnam said in an interview.

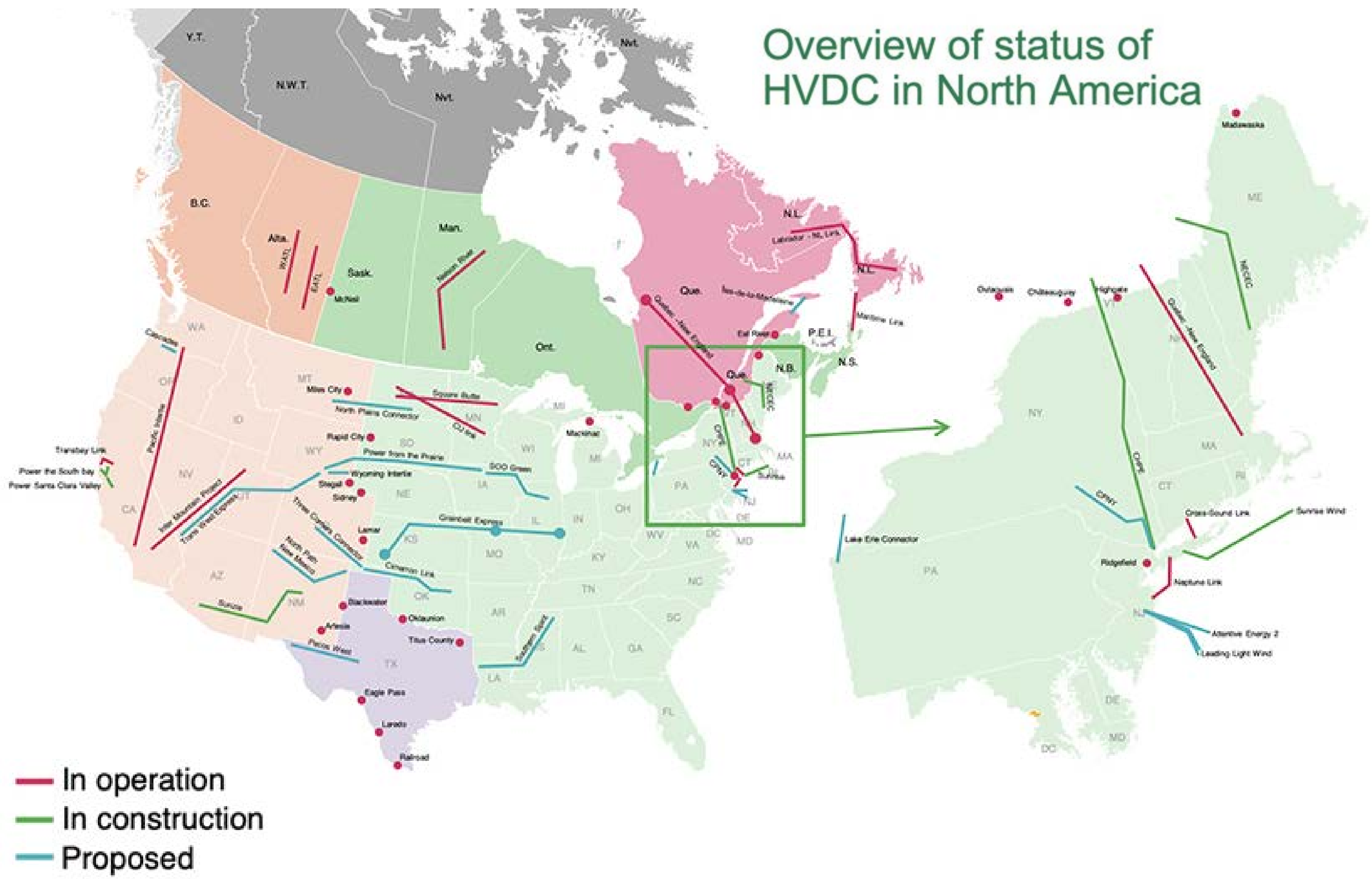
"If you look at Europe, there's a lot of work that's been done over the last decade to think through the various ways that an HVDC transmission system can operate and the various services that it can provide to the grid," Putnam said. "And in order to be able to enable those services, you have to define certain aspects of what the system will and will not do, so that you understand how it will impact the rest of the grid. ... We really haven't thought through that for the North American grid."

The AC backbone of the grid has been in place for over a century, so the country has not had to look at basic standards for it in generations, he added.

Putnam said the JIP's work is expanding to a "much larger effort" with the Department of Energy, National Renewable Energy Laboratory, RTOs, utilities and others. DOE will be funding a study process that lasts several years to identify gaps in standards, come up with a plan to fill them, and then implement that plan and remove barriers to wider use of HVDC.

High-voltage lines operate much better underground or underwater than AC transmission, and the technology offers efficiencies for long-haul overhead lines. Their power density is also higher than AC, meaning more power can flow over less actual infrastructure, DNV Principal Consultant Cornelis Plet said in the interview.

The JIP has identified 25 different standards that need to be defined, including active power control, reactive power control, power recov-



HVDC projects that DNV's Cornelis Plet presented at CIGRE in August. | *DNV*

FERC/Federal News

ery requirements, emergency power control and islanded operation.

The standards include issues at the national, regional and local levels. The developers that DNV worked with on the first phase came up with five areas that they want to see addressed the most: offshore design standards, performance standards, reliability standards, ISO/RTO manuals and utility interconnection manuals.

"As we are looking at substantially more HVDC projects going forward, in order to have a more efficient process, we really do want to standardize these 25 functional requirements," Putnam said. "And, so, what we've looked at is in the U.S., there's about 10 of them where there's some partial standardization, and then there's 15 that there's not any coverage at all."

Even the partially completed standards include plenty of work because they often address just one of the three to four likely use cases of HVDC transmission, he added.

Getting all the standards in place in the U.S. will require working with multiple agencies who oversee different aspects of the industry, compared to Europe where one grid code offers some standardization even across different countries, Plet said.

"There are a number of different hierarchical organizations that create rules that transmission providers have to adhere to," Plet said. FERC sets very high-level technical principles; he noted that last year it mandated HVDC as part of the transmission planning process. NERC sets the minimum technical standards for reliability, but Plet noted that many of their rules for HVDC are designed for overhead lines and need updates for subsea and buried cables.

Regional reliability entities have their role to play, as do ISOs and RTOs, which have to come up with ways to handle the technology in their interconnection and operational requirements.

"This is where developers of HVDC links often run into problems because ISOs often don't know how to treat an HVDC line," Plet said. "There's no specific class for it. Is it a generator? Not really, but it sometimes behaves a little bit like one. Is it a transmission line? Also not really, but it does have some of the transmission line functions. So how [do you] distinguish between that and ... create some clear connection requirements for HVDC systems that are not conflicting on both ends of the line? ... And this includes not only how should it be studied, but also how can it participate in the different power markets."

One hot topic has been whether an HVDC line designed to ship power from one region to another can participate in the capacity market on the delivery end, he added.

State regulators also have a role to play in that they are ultimately responsible for ensuring that consumers do not pay too much for energy, Plet said. The New Jersey Board of Public Utilities and New York Public Service Commission have mandated the use of HVDC lines for the offshore wind those states have procured, he noted.

Getting the standardization in place is a key hurdle to making HVDC a normal part of system planners' toolbox; Plet argued that the technology will be vital to expanding the transmission system.

"You need HVDC," Plet said. "You will not be able to build out enough new transmission capacity without it." ■

FERC/Federal News

FERC Approves $3B BlackRock Deal for Global Infrastructure LLCs

Combined Companies Would Have Overlapping Interests in Multiple Markets

By James Downing

FERC on Sept. 6 approved a deal in which BlackRock is seeking to buy all the limited liability company interests in Global Infrastructure Management for $3 billion in cash and 12 million shares of BlackRock Funding (*EC24-58*).

Global Infrastructure owns or controls 6,937 MW of generation in CAISO, 606 MW in PJM, 463 MW in ISO-NE, 787 MW in SPP and generation outside RTO/ISO markets. The company is also trying to buy 50% interest in North East Offshore, Revolution Wind and South Fork Wind, which are all developing offshore wind off the Northeast, and it has investments in FERC-regulated natural gas infrastructure.

BlackRock is a publicly traded investment management firm that controls gas-fired resources in various parts of the U.S., including 3,374 MW in PJM, 1,042 MW in Arizona and 945 MW in Georgia, as well as other facilities that fall under FERC jurisdiction.

The application drew a joint protest from Public Citizen, and the Private Equity Stakeholder Project and Sierra Club separately protested it.

The two firms' capacity overlaps in CAISO and PJM, where, after the deal is completed, BlackRock would control 10 and 2.2%, respectively, of generation in those markets. The percentage in California was high enough to require the applicants to run a delivered price test, which showed the combination lacks a material competitive effect on CAISO's market.

The joint protest argued otherwise, saying BlackRock should have to include any utility in which it holds 10% or more voting shares, which represents more than 20 firms. BlackRock said its shares in those firms are covered by an effective blanket authorization from FERC and it does not control them. (See *BlackRock Decision Unearths FERC Wariness of Investor Influence on Utilities*.)

FERC agreed with the applicants' findings that the deal would not impact horizontal market power and agreed that BlackRock does not need to include its investments covered by the blanket authorization in the analysis.

BlackRock does not exercise any control over those utilities, so it does not need to include their generation in the delivered price test, FERC said.

The joint protest argued that the application is silent on how BlackRock can manage its passive ownership of voting shares of utilities that compete with its active, direct holdings. They argued that FERC should conduct a formal reassessment of the blanket authorization as part of its review of the deal with Global Infrastructure.

FERC said under the blanket authorization, BlackRock agreed it would not exercise control over the day-to-day management of any covered utilities. It would be required to file a separate application if it sought to exercise direct control over the management or operations of a utility outside of that authorization, as it did with the Global Infrastructure deal.

"We decline to reassess BlackRock's blanket authorization in this proceeding or to hold a hearing on BlackRock's blanket authorization at this time," FERC said. "Questions about the conditions applicable to BlackRock's blanket authorization are beyond the scope of this proceeding."

'Economic Reality'

Commissioner Mark Christie wrote a concurrence to the order saying he's long been concerned about huge asset managers like BlackRock seeking to acquire interests in utilities. (See *FERC Reconsidering Blanket Authorizations for Investment Companies*.)

"The influence that large shareholders, BlackRock or otherwise, can potentially exert across the consumer-serving utility industry should not be underestimated," Christie said. "Such horizontal shareholdings pose the threat of decreased innovation, reduced competition and ultimately higher prices to consumers, as well as the prospect of chilling investment in exactly the new generation resources we need to meet increased demand for power and to enhance the reliability of the grid. So this is an issue that deserves much greater scrutiny, as I have stated before."

BlackRock already owned passive shares in IPPs in California and is now expanding its active control over more of them, but FERC cannot examine the issues cited in the protests because of the blanket authorization.

"You do not need a Ph.D. in economics to see the potential for anticompetitive conduct and outcomes when an investment entity like a huge asset manager seeks to own generation assets that will be — or should be — competitors," Christie said. "Market power is an ever-present concern, and one rule I taught my law students is that any seller with market power will use it. That's not a moral judgment, just economic reality." ■

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BPA to Fund Phase 2 of Markets+, Agency Exec Says

Bonneville Plans to Pay About $25M for SPP Market's Implementation Phase

By Robert Mullin

BPA's Bonneville Dam | *Travel Portland*

The Bonneville Power Administration plans to contribute its full share of funding for Phase 2 of SPP's Markets+, an executive with the federal power agency has said.

"BPA intends to continue its funding of the development of Markets+ as we proceed with our public process," BPA Vice President of Bulk Marketing Rachel Dibble said in a statement emailed to *RTO Insider*. "As outlined in our staff recommendation in April, Bonneville sees many benefits for its customers and the Pacific Northwest in SPP's Western day-ahead electricity market, particularly its independent governance model."

BPA used similar language when it announced Aug. 26 that it would postpone until next year its decision between Markets+ and CAISO's Extended Day-Ahead Market (EDAM), but it was unclear at the time whether the agency's mention of continued support for the SPP day-ahead market included a commitment to funding its share of the estimated $150 million price tag for the Phase 2 implementation stage of the market, which is scheduled to begin in 2025. (See *BPA Postpones Day-ahead Market Decision Until 2025*.)

"We are currently reviewing and negotiating Phase 2 funding agreements with SPP as are other utilities and participants. Ultimately, ensuring the viability of two day-ahead market options remains a key principle of our evaluation and decision process," Dibble said.

A *Sept. 5* article in the *Portland Business Journal* article quoted Dibble as saying BPA estimates its Phase 2 costs will come to about $25 million.

According to an SPP *document* dated July 31, BPA would be responsible for 17.4% of Phase 2 funding, second only to Powerex at 23.2%. Those percentages are likely to increase slightly after two Black Hills Energy utility subsidiaries recently committed to leave SPP's Western Energy Imbalance Service to join CAISO's Western Energy Imbalance Market, indicating their likely withdrawal from Markets+ development efforts. (See *CAISO's WEIM Plucks Black Hills Utilities from SPP's WEIS*.)

Controversy Accompanies Funding Decision

BPA's decision on whether to continue funding Markets+ represents yet another flashpoint in the already politically fraught atmosphere that has materialized around its process for choosing between Markets+ and EDAM.

The controversy has risen into the upper reaches of U.S. politics, with all four Democratic U.S. senators from Oregon and Washington in July sending BPA Administrator John Hairston a letter urging the agency to delay its day-ahead market decision until more developments play out around the two markets. That letter reflected many of the concerns of Northwest supporters of the EDAM, who fear BPA is moving too quickly in the direction of Markets+. (See *NW Senators Urge BPA to Delay Day-ahead Market Decision*.)

But BPA also faces pressures from below — in the other direction. A large contingent of BPA's base of "preference" customers — the Northwest publicly owned utilities that rely on the federal Columbia River hydroelectric system for low-cost power — has urged the agency to stay the course and continue funding Markets+ into its implementation phase and ultimately join the market. (See *Northwest Public Power Group Endorses Markets+ over EDAM*.)

Last month, 47 of those utilities collectively sent their own *response* to the letter from the Northwestern senators, asking the delegation to consider the impact of BPA's day-ahead market decision on the region's consumer- and tribal-owned utilities and cautioning them against applying pressure that could delay BPA's funding for Phase 2.

In a similar vein, Washington-based investor-owned utility Puget Sound Energy independently sent a *letter* to Washington Sens. Patty Murray and Maria Cantwell saying competition between the two markets "is proving beneficial for participants" and warning that "delaying market decisions will have the consequence of delaying real economic benefits to customers across the region."

On the other side of the debate, in conversations with *RTO Insider*, Northwest-based supporters of the EDAM have questioned the soundness of BPA committing so much funding to Markets+ ahead of other developments. Chief among them is the continued progress of the West-Wide Governance Pathways Initiative in moving CAISO's markets toward more independent governance — something BPA and other Markets+ supporters view with skepticism. (See related story *'Leaning' Evident in BPA Response to NW Senators*.)

One source, who is not authorized to speak on behalf of their organization, also pointed to the fact that, unlike the EDAM tariff, the Markets+ tariff still is in limbo after SPP's filing received a deficiency notice in July covering 16 items. That source pointed out the notice contained a number of substantive issues for SPP to address, including important details the RTO assumed could go into the market's business practice manual or protocols, but that FERC might require be included in the tariff itself.

For its part, SPP had expressed confidence it can address FERC's concerns about the Markets+ tariff. (See *SPP Dispels Concerns over Markets+ Deficiency Letter*.) ■

DOE Awards $430M for Hydro Maintenance

Grants Aimed at Improving Resilience of Country's Fleet of Aging Dams

By Elaine Goodman

The U.S. Department of Energy has awarded $430 million to nearly 300 projects at hydroelectric facilities to enhance dam safety, strengthen grid resilience and improve the environment.

The funding, announced Sept. 5, comes from the DOE's Grid Deployment Office through the Maintaining and Enhancing Hydroelectricity Incentive program.

The 293 *projects* to receive funding are spread across 33 states. Eighty-four projects focus on grid resilience, 149 are dam safety projects, and 60 are environmental improvement projects. Award amounts range from $7,200 to $5 million.

Hydropower contributes nearly 27% of the nation's renewable electricity generation and 93% of utility-scale energy storage. But the fleet is aging, officials noted. Facilities selected for funding are on average 79 years old.

For example, Entergy Arkansas marked the 100-year anniversary of the Remmel Dam this year. The DOE awarded $1.8 million for safety improvements at the dam.

"We're thrilled to invest in this hydroelectric fleet that is such an important part of our nation's electric system," Maria Robinson, Grid Deployment Office director, said during a news conference.

For the most part, the projects selected for funding through the Maintaining and Enhancing Hydroelectricity Incentive program won't increase generation or capacity, DOE officials said.

Rather, the program focuses on strengthening grid resilience at dams through measures such as turbine or generator replacement or transformer upgrades.

Safety measures funded by the program might include improvements to emergency spillways or concrete replacement to prevent water seepage through the dam.

In addition, the program funds environmental and recreational improvements such as fish ladders or improved boating access.

Entergy Arkansas is receiving DOE funding for safety improvements at the 100-year-old Remmel Dam — one of 293 projects being funded through the Maintaining and Enhancing Hydroelectricity Incentive program. | *Entergy Arkansas*

Multiple Awards

Many utilities are receiving awards for multiple projects. PacifiCorp Renewable Resources was awarded $38 million for nine projects, including $5 million each for the Fish Creek pumped storage facility and Weber Dam improvements.

Pacific Gas and Electric is receiving more than $34 million for 19 projects. Among the funding is $123,289 for improvements at the Potter Valley fish hotel and $5 million for the Lower Bucks spillway restoration project.

Michigan-based Consumers Energy is receiving about $23 million for 10 projects, including $5 million each for improvements at the Rogers and Hardy spillways.

Seattle City Light was awarded about $21 million for five projects, including $5 million for dam safety at the Cedar Falls hydroelectric project.

The Maintaining and Enhancing Hydroelectricity Incentive is one of three DOE programs that fund hydroelectric projects through the Bipartisan Infrastructure Law.

Another program, the Hydroelectric Production Incentives, will provide $125 million to hydroelectric facilities for electricity generated and sold. In 2023, 66 hydro facilities were awarded $36.7 million. Applications for a second funding round are now under review.

The third program, the Hydroelectric Efficiency Improvement Incentives, will invest $75 million into hydropower facilities. In February, DOE awarded $71.5 million to 46 hydroelectric projects in 19 states.

The Grid Deployment Office will discuss the latest Maintaining and Enhancing Hydroelectricity Incentive awards during a *webinar* on Sept. 11 from 1 to 1:30 p.m. ET.

DOE expects to announce a second round of funding for the program next year. ■

CAISO/West News

WestTEC Committee OKs Plan for 'Actionable' Tx Study

Study Will Seek to Inform Western Grid Planning over 10-, 20-year Horizons

By Ayla Burnett

The Western Transmission Expansion Coalition's (WestTEC) steering committee on Sept. 5 unanimously approved the plan that will underpin a Western transmission study designed to stimulate development of interregional projects over the next two decades.

"The study plan approval was the result of many months of collaboration within the WestTEC committees and with community and regional partners," Sarah Edmonds, CEO of Western Power Pool, which is coordinating WestTEC, said in a *press release*. "We are grateful to these partners who have helped get us this far and to the Western Electricity Coordinating Council as a major sponsor of our upcoming work."

WestTEC's *transmission study plan*, jointly facilitated by WPP and WECC, is an industry-led effort to address long-term interregional transmission needs as the grid expands and climate change accelerates. Approval of the plan commences the study itself, which will take place over the next two years.

The main objective is to create an "actionable" transmission study by conducting integrated planning analysis across the Western Interconnection that produces 10- and 20-year transmission portfolios. (See *Group Looks to Create 'Actionable' West-wide Transmission Plan*.)

The effort is voluntary, intended to respond to the "widely recognized concern that current transmission planning frameworks in the West do not result in the identification of sufficient transmission solutions to support the needs of the future grid and that interregional transmission planning can be strengthened," the study plan reads.

The study horizons focus on evaluating transmission requirements in 2035 and 2045, with the goal of prioritizing "flexible and scalable transmission solutions for nearer term needs to help better position the system for efficient long-run expansion."

Assuming the system will evolve based on current trends, existing policies, generation projections and load forecasts, the study will primarily reference the WECC 2034 anchor dataset, utility integrated resource plans, state agency data and other non-proprietary data sources.

| Stefan Andrej Shambora, CC BY-2.0, via Wikimedia Commons

The study isn't meant to replace existing transmission planning processes or alter FERC Order 1920 — the landmark ruling requiring regions to undergo long-term transmission planning — but to complement them.

Notable features of the transmission study include:

- a study footprint spanning the Western Interconnection, as well as interties connecting the Canadian provinces of Alberta and British Columbia.
- load-growth forecasts that capture the increasing demand for electricity.
- resource forecasts that result in a generation mix that meets state policy requirements, reflects clean energy goals and accounts for voluntary procurement of clean energy.
- consideration of multiple planning scenarios to reflect the inherent uncertainties of long-range planning.
- an integrated approach to identifying transmission portfolios, with an emphasis on identifying transmission needs not addressed by other planning efforts.
- regional partner engagement and governance.
- credible and objective study execution through an independent consultant team.

The study's goals include addressing reliability and commercial and economic efficiency by ensuring the footprint has sufficient transmission capacity to meet future energy needs while reducing congestion, identifying a plan that complies with NERC reliability standards and enabling operational efficiency.

WestTEC also aims to address affordability by unlocking the benefits associated with a coordinated transmission portfolio that can enable greater diversity in supply and demand. Other goals include increasing visibility into the combined capabilities and requirements of the study footprint and addressing cost allocation.

If those goals are met, backers of the plan hope the study will serve as input into local and regional planning processes; initiate bilateral negotiations and development activities; facilitate engagement with local communities, tribal nations and regulators; provide meaningful data; and a serve as a resource to developers, utilities and state regulators.

Study Limits

While WestTEC backers anticipate the effort will "fill many planning gaps currently present in the West," they also acknowledge its limits.

The study won't provide a comprehensive list of all needed transmission infrastructure, nor will it capture all the infrastructure needed to maintain economic and reliable operations.

It also won't focus on identifying infrastructure needed to address pre-existing reliability issues within a single transmission-owner area, or on resolving lower-voltage thermal issues "reasonably expected to be addressed through existing interconnection, local or regional planning processes, even if such issues are present on transmission infrastructure that would otherwise be in the scope of the assessment."

Additionally, the study offers a "point in time" view of transmission needs, meaning the projects explored by WestTEC will be implemented in response to evolving needs that will be clearer over time.

While WestTEC emphasizes the plan will not be a "singular transmission solution in the West," participants are confident the study will help ensure reliable and sustainable grid operations in the future.

The 10-year horizon study is already underway and is expected to be complete by September 2025. The 20-year study will begin in spring 2026, with the full report slated for September 2027.

"With this milestone, there's good momentum right now, and we need to keep our partners engaged and keep it going," Edmonds said. ■

Collaboration Key to Managing Growing Western Load, Panelists Say

WECC Discussion Explores Impact of Data Centers, Industrial Growth on Region's Grid

By Henrik Nilsson

Collaboration among stakeholders is crucial to maintaining Western grid reliability in the face of increasing demand posed by large loads such as new data centers, speakers said Sept. 4 during a webinar hosted by WECC.

Representatives from Elevate Energy Consulting, the Pacific Northwest Utilities Conference Committee (PNUCC) and the Grant Public Utility District in Washington participated in the webinar. The panelists discussed the challenges of integrating large loads in the Western Interconnection.

According to PNUCC's Northwest Regional *forecast* for 2024, electricity demand is projected to increase from approximately 23,700 average MW in 2024 to about 31,100 aMW in 2033, an increase of over 30% in the next 10 years.

"That is an increase of 7,000 average MW, or enough electricity to power seven cities the size of Seattle," said Crystal Ball, PNUCC's executive director. She noted the increase in demand is primarily from three things: data center development, high tech manufacturing growth and electrification.

"But really, we see it coming from these companies developing large data centers in the Pacific Northwest," Ball added.

Grant County has been dealing with the increase in large loads for some time, according to Shane Lunderville, business development manager for the county's publicly owned utility.

"We've had data centers for the last 10 years and a lot of growth that has not stopped," Lunderville said. "We have averaged in just industrial growth between 5 to 7% per year of that growth, and we're not seeing it slow down."

Ball said the increased demand for electricity is a sign of economic growth opportunities. However, it also poses significant reliability challenges, such as integrating large loads while adhering to efforts to reduce carbon emissions.

"One misstep really could lead to cascading consequences," according to Ball. "It's really the reliability of the power system that is at risk during this transition while meeting this increasing demand for electricity."

She added that stakeholders must work collaboratively and focus on proactive solutions.

Kyle Thomas, vice president of compliance services at Elevate Energy Consulting, agreed, saying that "all parties have to be at the table."

"Doing one thing on the grid actually involves many different departments … because it's so interconnected, it's so involved, and the data centers is no exception," Thomas said. "So, we need policy, we need regulatory, we need legal, we need the engineers."

However, according to Thomas, one issue is that data centers often have strict confidentiality rules because of the competitive space between different developers. This makes it difficult to study how to best integrate data centers while ensuring reliability, he said.

"We should still start and try and figure out where our gaps of knowledge are and partner with them to get information, get data, get models, and then learn from these real operations with monitoring data and get that cycle as fast as possible," Thomas said.

The U.S. could also learn from other countries that have successfully brought on data centers while ensuring the reliability of the grid, according to Thomas.

"You look at Ireland and their adoption of data centers is unbelievable," he noted. "You look at the [European Union], they have had interconnection requirements in place and policies for large loads since about 2009. We can learn from others in the collective global industry here to learn and accelerate our knowledge where it may be lacking, and we can also help others in that aspect." ■

New data centers will be among the largest contributors to rapid load growth in the Western U.S. | *Amazon*

CAISO Interconnection Enhancements Proposal Still in Flux

ACP-CA Proposes Refining Process of Allocating Transmission Plan Deliverability

By Ayla Burnett

The issue of how to allocate transmission plan deliverability (TPD) for projects with long lead-time network and reliability upgrades remained the center of discussion at a Sept. 4 CAISO Interconnection Process Enhancements Working Group meeting.

The stakeholder group focused in part on whether to retain or do away with TPD allocation Group D. (See *CAISO IDs More Challenges in Refining Interconnection Process*.)

CAISO allocates TPD to projects separated into four groups. Group A is for customers with executed power purchase agreements and those in the current queue cluster that are load-serving entities serving their own load. Group B includes those actively negotiating a PPA or on a shortlist. Group C is for those that have received commercial operation for the capacity-seeking TPD.

Group D consists of interconnection customers electing to be subject to the Generator Interconnection and Deliverability Allocation Procedures (GIDAP) section (8.9.2.3) in CAISO's tariff. Being part of that group comes with certain requirements that the ISO and stakeholders considered potentially too restrictive. An interconnection customer in Group D cannot request suspension under the ISO's Generator Interconnection Agreement (GIA), delay providing its notice to proceed as specified in its GIA or delay its commercial operation date (COD) beyond the date in its interconnection request.

In the Track 3 revised straw proposal, CAISO proposed eliminating Group D.

Bob Emmert, CAISO senior manager of interconnection resources, said cluster 14 of the CAISO interconnection queue included many projects that were unable "to get an allocation through the PPA path or shortlisted path, so they went and chose the allocation group D path."

"So, a lot of capacity was allocated to those projects, which is actually impacting the [number] of projects that can be studied in cluster 15," Emmert said. "We didn't think that was really the best way to go — to, each year, give out some conditional type of allocations through allocation group D and then kind of shortchange the next cluster group on the number of projects that can be studied."

Los Banos Substation in California | *JPxG, CC BY-SA 4.0, via Wikimedia Commons*

But some stakeholders were concerned about eliminating the group, given the long timelines for developing transmission.

"The prospect of requiring a short list or PPA to secure deliverability when the resource may not be able to come online and secure deliverability for approximately 10 years is problematic because contracting that far into the future increases risks," said a presentation given by the American Clean Power Association-California (ACP-CA) during the meeting.

Group D was initially created to give off-takers more assurance for an allocation within the procurement process. Rather than having to wait for the results of the next TPD allocation cycle, some projects will already know they have an allocation, providing increased certainty for LSEs. In light of that benefit, Emmert reversed the ISO's initial suggestion to get rid of the group and instead suggested removing its restrictions and retaining it.

"The pro in this is … it works well for the process where people are negotiating a PPA and they know whether they have an allocation or not if they follow through with a PPA in time," Emmert said. "The con is it will impact the next cluster by reducing the number of projects that would be studied."

'Conditional Deliverability'

In its presentation, ACP-CA offered a proposal to revise the treatment of Group D, which could be a middle ground between retaining and doing away with the group.

"We share the concerns that have been expressed and the issues CAISO has raised around long development timelines for transmission projects and upgrades and aligning those with reasonable commercial timelines," said Caitlin Liotiris, a principal at Energy Strategies, who spoke on behalf of ACP-CA. "We also recognize the importance that Group D has played in the commercial process to date, and so are kind of eager to consider an alternative approach to Group D that might continue to provide some of the benefits of the past, perhaps with some additional timeline considerations to help better align the interconnection and TPD allocation timelines with more realistic and achievable commercial milestones."

ACP-CA's proposal involves retaining Group D and renaming it "conditional deliverability," making any deliverability allocated to this group "conditional."

The conditional deliverability allocated would not reduce the calculation of deliverability available for future clusters under the zonal approach and the 150% zonal limits.

Priorities would be assigned to conditional deliverability allocations, where the first group of projects with this allocation in each TPD allocation cycle would be given first priority, and so on. The priority positions would tell off-takers the likelihood of the project receiving a "standard" group A, B or C deliverability allocation. Rules for determining which projects would be able to convert from conditional deliverability would still need to be established, Liotiris said, such as how to prioritize projects with a PPA over those short-listed or whether to use a scoring methodology.

The ISO said it would need more time to consider whether the proposal could be implemented as part of the interconnection process.

"I think the ISO team needs to come together and discuss this a little bit more," said Danielle Mills, CAISO principal of infrastructure policy development. "I think there may be some changes to the study process involved in implementing a proposal like this, but it's probably a little early for us to explain what those would be until we think about it a little further." ■

ERCOT News

Texas PUC Rejects Possible 'Fraudulent' Loan Application

NextEra Energy, Claimed as Partner, Disavows Aegle Power

By Tom Kleckner

Texas regulators have rejected the second-largest project from its portfolio of potential generation resources that would be built with state funds.

The Public Utility Commission said Sept. 4 that a project put forward by Aegle Power had failed the due diligence portion of the Texas Energy Fund's loan-application process. The project's developer had said NextEra Energy was a party to the application, but the Florida company told the PUC that it was not involved.

"Please be advised that NextEra's name was submitted in the Aegle application without NextEra's knowledge or consent," General Counsel Mitchell Ross wrote to the commission in a *letter filed* Sept. 3. "NextEra is not seeking funding as part of the TEF Program, is not participating in the project for which NextEra was named, and hereby requests that NextEra be immediately removed from PUCT records as a sponsor for the Aegle Power project."

Doug Lewin, Stoic Energy Consulting's principal, came across the letter while searching regulatory filings in PUC dockets and raised its profile on social media.

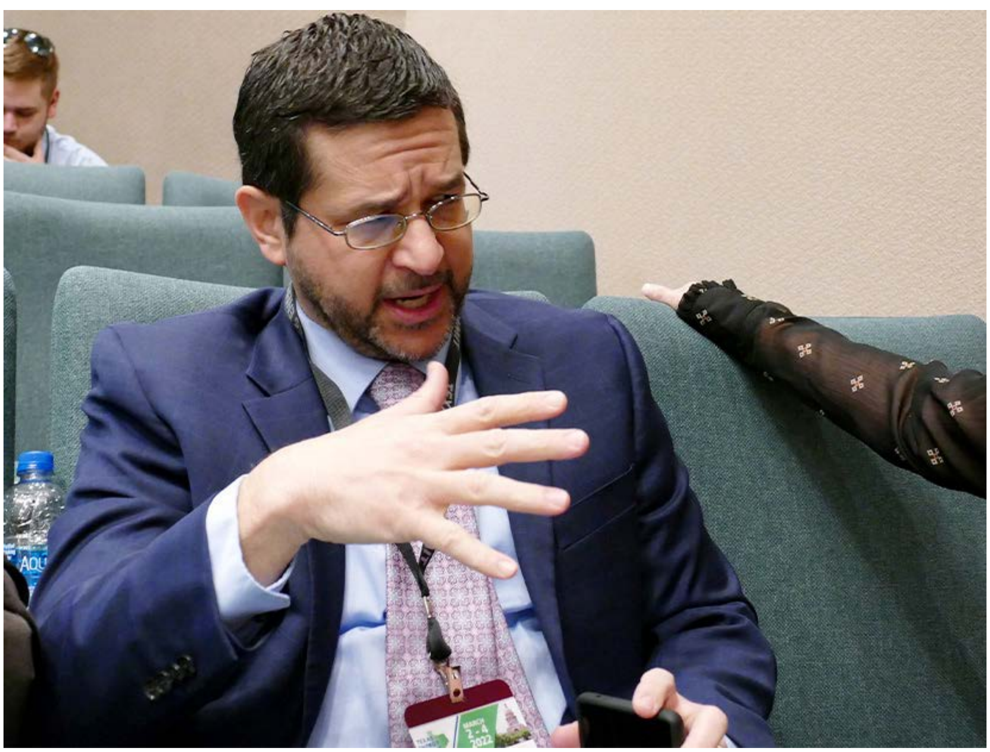
"Not a great start," he *posted* on X, formerly known as Twitter.

It gets worse. Lewin discovered that Aegle's CEO, Kathleen Smith, had *pleaded guilty* in 2017 for embezzling a "significant" amount of money from a company that was trying to build a power plant in Corpus Christi, Texas.

"It was not like they created some crime in Europe. It was in Texas on a power plant," Lewin told *RTO Insider*.

Smith was president of Chase Power Development, which cited low gas prices and difficulty in securing environmental permits when it *abandoned* the $3 billion Las Brisas Energy Center project in 2013 and said it was going out of business. The plant was to burn petroleum coke from nearby oil refineries.

The Aegle project would supposedly have built a combined cycle facility in the Rio Grande Valley with a nameplate capacity of 1,260 MW. It was among the 17 applications selected for further review as part of a *$5 billion loan program* intended to add thermal generation to the ERCOT grid. (See *PUC Shortlists 17 Projects for Loans from Texas Energy Fund*.)



Research from Stoic Energy's Doug Lewin helped reveal a problematic Texas Energy Fund project that has since been rejected. | *© RTO Insider LLC*

PUC Executive Director Connie Corona said the commission is "still a long way" from selecting the companies that will receive TEF loans.

"Proposed projects that have reached this stage have only met the initial requirements for applications," she said in a *statement*. "We have a multistage application and verification process that gets more rigorous at every step to ensure only financially sound applicants with viable projects receive these loans."

The commission said it will pursue at least a 10% repayment from the TEF contractor, Deloitte. The advisory services firm conducted the first review of applications.

In *testimony* before the state Senate Finance Committee on Sept. 5, PUC Chair Thomas Gleeson said the commission had learned the previous week that one of the TEF applications was "perhaps submitted with potentially fraudulent information."

"While I am absolutely certain that this this project never would have gotten funded, and we assumed that some projects would fall out ... it is still unacceptable to have moved this forward," he told the committee. "I think it is clear that our contractor needed to do better in their initial review of this company and that our staff needed to hold our contractor more accountable for that review. ... We should have asked a lot more questions about these companies."

State Sen. Charles Schwertner (R), who authored the bill authorizing the TEF (*Senate Bill 2627*), called the developments "disappointing" and promised "hard questions" during a Texas Energy Fund Advisory Committee joint oversight hearing with House members Oct. 8.

Schwertner said the request for a contract administrator included "very specific requirements of the ... contract administrator regarding fraud prevention." He also raised issues around NextEra's involvement in the application, noting that their letter to the PUC "doesn't say they didn't have a relationship" with Aegle.

Gleeson told Schwertner that NextEra has a nondisclosure agreement with Aegle. He said that in a call with the company Sept. 4, he asked NextEra to "reconsider their stance" and break the NDA.

"They informed me that they were not chang-

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ing their stance," Gleeson said.

"I don't know what's going on with NextEra about their relationship here with this applicant, Aegle Power, but I want to know," Schwertner said. "We're going to get to the bottom of it, whether it requires subpoenas to [legislative committees], but this is unacceptable that we have large publicly traded companies as well as new entrants with questionable backgrounds."

"This doesn't smell right. I'm not believing everything I'm hearing," said Sen. Joan Huffman (R), the committee's chair and a member of the TEF Advisory Committee.

The PUC says it expects the due diligence review to take up to eight months. Commission and Deloitte staff will verify each project's details, including participating companies, financial viability, construction plans, interconnection capabilities, ability to complete the project and ability to pay back the taxpayer-backed loans, the PUC said.

Texas PUC Chair Thomas Gleeson and Executive Director Connie Corona appear before a Texas Senate committee. | *Texas Senate*

While the lawmakers questioned the initial vetting process, Stoic's Lewin said his concerns lie with the 10 GW of dispatchable thermal generation that the TEF is designed to construct.

"It looks to me that they were trying to pick a whole lot of different generators. Seventeen different projects, but there are not really 17 difference credible thermal energy generation developers in Texas," Lewin told *RTO Insider*. "Somebody really wants [new thermal capacity] to be 10 GW. I want to see the study that says 10 is the number. Where's the data, where's the study that says 10 is the magic number?"

Lewin advocates for microgrids and backup power packages that can be used at the local level, such as during the recent Hurricane Beryl, and funding for wires infrastructure and generation facilities in Texas' non-ERCOT regions. He said the two TEF programs could be at risk should the push for 10 GW of thermal generation encroach upon their funding.

"You have credible power companies out there," Lewin said. "Let them do their projects and stop fixating on 10 GW." ■

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Texas PUC Sets Reliability Standard for ERCOT

Commission OKs VOLL, Market Design Recommendations

By Tom Kleckner

Texas' regulatory commission has adopted a reliability standard for the ERCOT region, one of several policy parameters that will be used in upcoming analyses for the proposed performance credit mechanism (PCM) market design.

As approved by the Public Utility Commission during its Aug. 29 open meeting, ERCOT must meet three criteria to comply with the *reliability standard*: frequency, duration and magnitude. To meet the standard, ERCOT outages should not occur more than once in 10 years on average, last more than 12 hours or lose more power than can be safely rotated (*54584*).

"Our system must continue to evolve to meet the growing demand for power in our state ... it's critical we clearly define the standard at which we expect the market and system to operate," PUC Chair Thomas Gleeson said in a *statement*. "By establishing a reliability standard for the ERCOT region today, we are setting a strong expectation for the market and charting a clear path to further secure electric reliability."

The new rule also establishes a process to regularly assess the ERCOT grid's reliability. The commission directed ERCOT staff to conduct a probability-based assessment every three years, beginning Jan. 1, 2026, to determine whether the system is meeting the standard and is expected to continue to do so over the next three years.

Should that assessment indicate the system fails to meet the reliability standard, the Independent Market Monitor (IMM) must conduct an independent review and commission staff must recommend their own potential market design changes. The PUC then would review ERCOT's assessment, the IMM's review, commission staff's recommendations and public comments to determine whether any market design changes are necessary.

ERCOT and IMM staff confirmed during the meeting that they have all they need to begin their respective analyses. Draft results are due to the PUC in early November; the commission will consider the final results in December.

The ISO said it will use 19 GW as the amount of load it can safely rotate during an outage in its cost/benefit analysis, as it proposed in an April *research paper*.

ERCOT's Chad Seely explains the ISO's change in direction on must-run alternatives to a reliability must-run contract. | *Admin Monitor*

The reliability standard was just one of several actions the PUC took to establish regular assessments of the grid's ability to meet demand and help determine any necessary future improvements.

It adopted a value of lost load of $35,000/MWh, using information from a *survey* of ERCOT consumers and a *Brattle study*. Staff *proposed* a $30,000 VOLL, but Gleeson *recommended* Brattle's suggested $35,685, saying it was "reasonable" after a "detailed and thorough" analysis (*55837*).

"We don't need the extra numbers in there," Gleeson said.

ERCOT will use VOLL for cost/benefit analyses in its planning models. The PUC said it will not be used to update the operating reserve demand curve or any current market-design elements.

The commission also accepted staff's final recommendations for each of the PCM's *37 base case parameters*, including a firm $1 billion gross cost cap to comply with state law (*55000*). ERCOT had proposed a counterfactual of energy-only market equilibrium reserve margin instead of the cost cap, a "purely theoretical number," according to Stoic Energy principal Doug Lewin.

PUC staff and ERCOT also differed on four other parameters: the metric to determine performance credit (PC) hours; a duration-based cap for consecutive PC hours; the net-cost cap compliance framework; and non-performance penalties for PCs offered but not cleared in the forward market.

The PUC selected the PCM from among five other suggested market reforms as its design of choice and approved it in 2023. That same year, the Texas Legislature passed a bill setting a $1 billion annual cap for the PCM. (See *Texas PUC Submits Reliability Plan to Legislature*.)

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The PCM will use the reliability standard and a corresponding quantity of PCs that must be produced during the highest reliability risk hours to meet the standard. Load-serving entities can purchase PCs, awarded to resources through a retrospective settlement process based on availability during hours of highest risk, and trade them with other LSEs and generators in a forward market; generators must participate in the forward market to qualify for the settlement process.

CPS Energy MRA, RMR Update

ERCOT told the PUC it has changed course on must-run alternatives for three retiring CPS Energy coal units, postponing an inspection of the largest unit until after the winter season (*55999*).

The San Antonio municipality told the commission this year it planned to retire the three coal units, which date back to the 1960s, in March 2025. However, ERCOT said the Braunig Power Station units, with a combined summer seasonal net maximum sustainable rating of 859 MW, were needed for reliability reasons and *issued a request* for reliability-must-run proposals in July. (See *ERCOT Evaluating RMR, MRA Options for CPS Plant*.)

The grid operator said in an *update to the commission* that while it continues to negotiate a potential agreement with CPS Energy to inspect the 412-MW Unit 3, it would be "more prudent" to allow the resource to operate through the winter's peak demand period. ERCOT staff said the inspection could be held in mid-February or early March.

"If we waited until after winter peak load, we believe we'd still have plenty of time, barring unforeseen circumstances, to have the unit inspected and repaired during another shoulder season for outages and before the summer peak load season," ERCOT's Davida Dwyer said.

The ISO extended the deadline for RFP responses to Oct. 7 after receiving fewer than 10 proposals to its initial request. (See "ERCOT Extends MRA Timeline," *ERCOT Board of Directors Briefs: Aug. 19-20, 2024*.)

Chad Seely, the ISO's general counsel, told the commission the deadline would provide an "important data point" in seeing whether the industry has responded with enough MW to provide relief for a constrained area south of San Antonio.

"The additional time affords us a more deliberative process on these critical policy issues to see if the industry is going to respond to the must-run alternative," Seely said, "and then continue to move forward [on] a path where we still think it's appropriate and prudent for reliability to start to open up the unit in advance of any April 1 RMR agreement."

"Is it looking bleak on the MRA?" Commissioner Lori Cobos asked Seely.

Noting that ERCOT has amended the RFP after stakeholder feedback, he said, "We're hopeful, with the amendments that we put forward and allowing almost another month of time for people to go do their due diligence, and talk to their shops about options, that we will see a higher [number] of offers come in in October."

"Ultimately, I don't want RMR to be the norm, right?" Cobos responded.

Seely said the three units are in a "prime" location to relieve the constraint's interconnection reliability operating limits (IROLs), which makes the pre-RMR inspection work such an "extraordinary situation."

"[Braunig] is one of the best assets right now in the system, until we see other solutions to help relieve the overloads of the IROL for the next couple of years," he said. "That's why it's critically important to be deliberative and these critical policy issues on how we approach this."

CPS has said it will cost about $22 million to inspect, repair and prepare Braunig Unit 3 to remain in service past March and an additional $35 million for the other two units.

Utility and energy storage company Eolian *announced* Aug. 28 an agreement for two storage facilities south of San Antonio totaling 350 MW of capacity. The projects are not expected to come online until 2026, but work to upgrade the transmission infrastructure and relieve the South Texas constraint isn't expected to be completed until the middle of 2027. ■

ISO-NE News

NEPOOL Participants Committee Votes to Support Hourly GIS Tracking

Changes to PFP Financial Assurance Policy Narrowly Rejected

By Jon Lamson

The NEPOOL Participants Committee voted Sept. 5 to update the Generation Information System (GIS) to enable the transfer of hourly certificates, opening the door for the sale of hourly renewable energy credits.

Constellation Energy, which developed the proposal, had argued that hourly tracking is the logical next step in the evolution of RECs and would help incentivize carbon-free resources.

"Customers are looking beyond annual procurement of clean energy and unbundled clean energy attributes [toward] supply options that match generation with hourly consumption," Constellation's Gretchen Fuhr told the Markets Committee this year. "ISO-NE is already a leader in tracking all generation sources. Tracking hourly attributes is the next step."

The proposal failed to gain the approval of the MC in July but received 69.6% support from the PC. (See *NEPOOL Markets Committee Restarts Work on Capacity Market Changes*.) PJM rolled out support for hourly RECs in 2023. (See *PJM EIS Announces New Hourly Clean Energy Certificates*.)

The GIS system is administered by APX, which will develop the changes needed through 2025. The update is expected to cost an additional $75,000.

Financial Assurance Policy Changes

The PC did not reach a consensus to support proposed changes to the Pay-for-Performance (PFP) financial assurance policy, which ISO-NE has said are important to reduce the risks of generators defaulting on their payments.

In a memo prior to the meeting, ISO-NE wrote that it "has identified a fundamental gap in its credit risk management approach regarding the mitigation of PFP penalty payment defaults. The ISO's proposal to assess capacity sellers' liquidity and require more collateral from higher-risk entities on an ongoing basis addresses this risk."

The PFP rate is set to increase from $5,455/kWh in the current capacity commitment period to $9,377/kWh in 2025/2026.

The RTO has proposed to introduce "a corporate liquidity assessment to evaluate PFP penalty default risk that could result in additional financial assurance requirements for higher-risk market participants."

Following the liquidity assessment, ISO-NE would assign market participants a risk category, which would determine its financial assurance requirement. Some generators have expressed concerns about added costs associated with the additional financial assurance requirements.

To help limit overall risks, the New England Power Generators Association proposed a pair of revisions to the proposal: delay the implementation date of the revisions and add flexibility to the ability of generators to trade out capacity supply obligations. (See *ISO-NE Outlines 'Straw Scope' of Capacity Market Reforms* and *NE Generators Propose Financial Assurance Changes*.)

ISO-NE's proposal failed to pass the two-thirds approval threshold with 62.5% in favor, while NEPGA's revisions also failed with 47% and 53% in favor, respectively.

Despite that, a spokesperson for ISO-NE said the RTO is planning to file its proposed changes with FERC.

COO Report and Aug. 1 Scarcity Event

About 1,150 MW of generator outages and reductions, higher-than-expected temperatures, a pair of constrained interfaces and about 350 MW of out-of-service fast-start resources combined to cause ISO-NE's capacity scarcity condition on Aug. 1, COO Vamsi Chadalavada *told the committee*.

Chadalavada noted that the RTO entered the day with a limited capacity surplus and experienced about 750 MW in outages prior to the scarcity event. An additional 400 MW in outages occurred as the grid approached peak load, he added.

The Aug. 1 peak load was the highest of the month, at 23,758 MW. Oil generation on the system increased drastically for the peak, while hydro resources also ramped up significantly.

PFP charges for underperforming resources totaled about $50 million during the event. The average systemwide LMP reached $2,113/MWh during the peak hour.

For the month, the real-time hub LMP averaged about $39/MWh, Chadalavada said. The overall monthly energy market value was $403 million through Aug. 27, compared to $674 million in July and $310 million in August 2023. The Forward Capacity Market value was $120 million.

Chadalavada's monthly *report* indicated that the New England grid's carbon emissions for the year continue to outpace those of 2023, largely because of increased natural gas emissions.

Order 2222

Also on Sept. 5, FERC accepted by delegated order a compliance filing by ISO-NE for Order 2222 that specifies the deadline for meter data submission (*ER22-983-008*). The proposal was not protested by any parties.

Order 2222 directs grid operators to allow aggregations of distributed energy resources to participate in wholesale markets and has spurred a series of compliance filings from ISO-NE. (See *Still More Work for ISO-NE on Order 2222 Compliance* and *FERC Directs ISO-NE to Submit Another Order 2222 Compliance Filing*.) ■

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MISO News

MISO: 50% Peak Load Cap, Software Help Key for Crowded, Delayed Queue

By Amanda Durish Cook

MISO is adamant it should limit project proposals in future queue cycles to 50% of annual peak load to moderate its 300-GW, oversaturated queue.

During a Sept. 3 Interconnection Queue Process Working Group teleconference, MISO's Ryan Westphal said an annual megawatt cap, in conjunction with a tech startup's software for study help, will allow MISO to build study models faster without the "engineering problem" of too many hypothetical overloads, network upgrades and resources exceeding load. (See *MISO Sets Sights on 50% Peak MW Cap in Annual Interconnection Queue Cycles*.)

"We think that gives us the best chance of moving faster," Westphal said of overall queue processing.

MISO's current queue stands at 321 GW.

Westphal said a cap won't hinder MISO's resource adequacy, either. Using the queue's historical 21% completion rate, Westphal said MISO stands to add roughly 67 GW within a few years, even with capping entrants.

In the long run, MISO estimates 310 GW will be able to hook up to the system through 2042. Westphal pointed out that figure exceeds the 248 GW of additions by 2042 that MISO uses in its current transmission planning scenario. Westphal said that number should allay stakeholders' resource adequacy concerns, where a cap might restrict too many projects from connecting.

Clean Grid Alliance's Rhonda Peters asked how MISO plans to factor in significant new load additions in its annual megawatt cap.

Westphal said the cap calculation will be based on peak load using MISO's five-year out models, which should capture definite load additions.

"Using what's in the models as firm makes the most sense," he said.

Westphal also said MISO's attempt to conquer its unwieldy queue using Pearl Street's study software will not negate the need for a cap.

MISO will lean on Pearl Street's *SUGAR* (Suite of Unified Grid Analyses with Renewables) software to conduct screening of projects prior to conducting studies in earnest and to perform the first phase of studies in the queue.

MISO has delayed kickoff of studies on the 123 GW of projects that entered the queue in 2023 while Pearl Street assists with modeling. When the 2024 cycle will begin is an open question, since MISO intends to have the cap in place before it formally accepts a new cycle. (See *2023 Queue Cycle Delayed into 2025 as MISO Seeks Software Help on Studies*.)

"We have long been proponents of technology adoption in this space," NextEra Energy's Erin Murphy said, thanking MISO for reaching out for third-party help. However, Murphy said that if MISO and Pearl Street can achieve faster study results with more variables, that could negate the need for a megawatt cap on annual queue cycles.

Westphal said while SUGAR may help speed up study processing, without a queue cap, MISO still would run into the familiar problem of unrealistic dispatch models overflowing with too many projects.

Westphal said MISO still wants to return to its usual cadence of one-year queue cycles where submissions are accepted in the fall, validated through the holidays and begin studies in the new year, after MISO's Board of Directors approves MISO's planning models. However, Westphal added that it doesn't make sense to accept a new queue cycle if the previous cycle isn't far enough along in the study process.

| Northern Indiana Public Service Co.

Last month, the Union of Concerned Scientists' Sam Gomberg suggested MISO plan to play "catch up" on queue studies if Pearl Street's software proves successful. He suggested MISO consider accepting multiple queue cycles in a year to get back on track.

MISO is not entertaining using a volumetric price escalation — where developers pay fees that increase as they submit more projects for study — in lieu of a cap, as some stakeholders requested. Westphal said enacting escalating fees won't solve MISO's underlying "technical issue" of trying to study "load being served by too many generators."

"In our minds, it's not an alternative for a cap. We still believe we need that hard cap there to get us to reasonable study parameters and dispatch [model]," he said.

Several MISO generation developers argued that a volumetric price escalation would encourage interconnection customers to put only their best projects forward, discourage manipulation of the queue and allow small developers and co-ops an even playing field for submitting projects.

Savion's Derek Sunderman said MISO could police the volumetric approach by requiring large corporations to sign forms attesting to their subsidiaries. Sunderman requested that MISO conduct a stakeholder vote to gauge whether stakeholders prefer the cap or a volumetric price escalation.

Some stakeholders have asked MISO to consider giving developers estimated network upgrade costs at the screening stage of queue, if Pearl Street is proven effective at anticipating results.

MISO still is drawing up a plan to reevaluate the queue cap after three annual cycles, Westphal added. A few stakeholders have asked MISO to view the cap as a short-term measure and commit to sunsetting the cap after three years of use.

"Unfortunately, there's no silver bullet on the queue. It's just constant improvement," Westphal said.

MISO has scheduled a special meeting Sept. 30 to discuss the queue cap again. Westphal said he hopes to present "a final go" of the queue cap by then, make a filing at the end of October and earn FERC approval by the end of the year. ■

MISO News

MTEP 24 Reaches Almost $7B; MISO Ending Rush Island Reliability Agreement in Mid-October

By Amanda Durish Cook

MISO's 2024 transmission planning cycle is shaping up to include 459 new projects totaling $6.7 billion. The RTO shared the plan with stakeholders in a series of subregional planning meetings.

The 2024 Transmission Expansion Plan (MTEP 24) investment contains a little more than $1 billion in baseline reliability projects and $763 million in transmission projects needed for generator interconnection. In keeping with previous MTEP packages, the "other" category takes the largest share of investment, this time at more than $4 billion. "Other" projects include those needed for load growth, transmission owners' local reliability criteria, and to address the age and poor condition of facilities.

Projects driven by load growth and replacement of subpar facilities will take the largest share of investment this year, at about $1.5 billion apiece.

Senior Expansion Planning Engineer Amanda Schiro said this year, six of the top 10 most expensive projects are in MISO South, with all but one driven by the region's load growth. This year's most expensive baseline reliability projects also are in MISO South and involve rebuilding lines and substations, Schiro said during a Sept. 5 Central Subregional Planning meeting.

In a departure from previous years, the 2024 MTEP includes $858 million under what MISO classifies as "transmission delivery service."

The pair of projects submitted by Minnesota Power — one costing $800 million and the other $58 million — would modernize and upgrade Minnesota Power's existing HVDC system. The HVDC project is MTEP 24's priciest submittal.

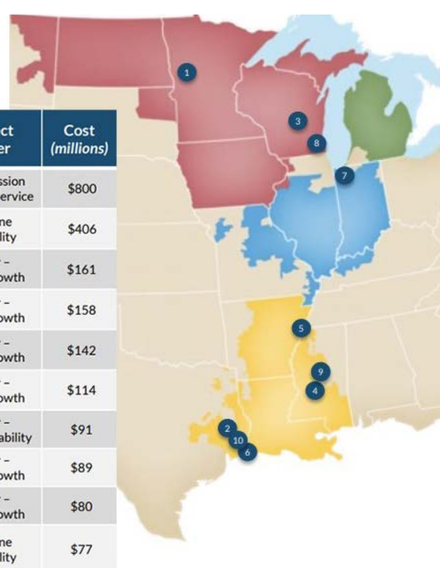
By planning region, MISO West accounts for almost $2.7 billion, MISO South $1.8 billion, MISO Central $1.4 billion and MISO East $771 million.

In MISO South, a single Entergy Texas reliability project is set to account for 40% of the region's spending. Entergy Texas' 500-kV Cypress-to-Legend line is estimated at $406 million. MISO said the reliability project performed better when compared to the 500-kV Hartburg-Sabine junction project, which MISO canceled in 2022 after a legal battle and the need for the project evaporated.

The Southern Renewable Energy Association had requested that MISO explore resurrecting the $134 million Hartburg-Sabine in place of Entergy Texas' project. (See "Return of Hartburg-Sabine Junction?" *MTEP 24 up to $5.8B; Clean Energy Group Asks for Alternative to Pricey Entergy Reliability Project*.)

MISO will use another project alternative over a transmission owner's original project submission. MISO recommended that Michigan Electric Transmission Co. pursue a $45 million relocation of the 138-kV Iosco-Karn line near Michigan's thumb area rather than a $74 million rebuild. The alternative project involves stringing lines on existing poles.

Rank	Project Name	Project Driver	Cost *(millions)*
1	HVDC Modernization Project	Transmission Delivery Service	$800
2	Cypress to Legend 500 kV line	Baseline Reliability	$406
3	Dodge County, DIC, New Substation	Other – Load Growth	$161
4*	Andes 500/230 kV Substation	Other – Load Growth	$158
5	Galet 500/230 kV New Substation	Other – Load Growth	$142
6*	Sandling 230 kV Customer Load Addition Project	Other – Load Growth	$114
7*	Aetna Synchronous Condenser	Other – Local Reliability	$91
8*	Racine County, DIC, Nimbus Substation	Other – Load Growth	$89
9*	Virlilia 230 kV Substation	Other – Load Growth	$80
10*	Legend to Sandling 230 kV Circuit 2 Project	Baseline Reliability	$77



MTEP 24's most expensive projects | *MISO*

The MTEP 24 package is larger than MISO anticipated earlier this year and smaller than last year's record-breaking $9 billion portfolio. (See *Early MTEP 24 Designates $5.5B in Transmission Spending* and *MISO Board Approves $9B MTEP 23; Members Deliberate on New Expedited Review Rules*.)

Schiro said officially, MTEP 24 will include not only the traditional MTEP spending, but also it and SPP's $2 billion Joint Targeted Interconnection Queue portfolio and its second, likely $25 billion long-range transmission plan, bringing total 2024 investment to almost $34 billion.

MISO will dedicate a special teleconference of the Planning Advisory Committee Oct. 1 to reviewing the draft MTEP 24 package of projects.

Rush Island SSR to End Oct. 15

MISO announced that its sole system support resource (SSR) agreement will get a final month-and-a-half extension as the Missouri coal plant associated with it is ordered offline by a federal court.

Ameren Missouri's Rush Island coal plant is supporting the MISO system from Sept. 1-Oct. 15 under a final SSR agreement. After that, Rush Island will go dormant, ordered offline by the U.S. District Court for the Eastern District of Missouri following years of Clean Air Act violations. (See *Ameren Files to Recoup Rush Island Closure Costs from Customers*.)

"The boilers are shutting down with or without an SSR agreement," MISO planner Grant Larson told stakeholders.

MISO said it won't need the SSR once three MVAR static synchronous compensators are installed on the nearby system. Those upgrades aren't expected until December, resulting in weeks of potentially precarious operations.

"MISO is prepared to address any operational issues that may arise following the retirement of Rush Island," MISO spokesperson Brandon Morris said of the gap period beginning in mid-October.

Morris emphasized that MISO planning studies show no concerns once transmission upgrades are in place this December.

The plant has been operating for about two years under SSR agreements, which are used to keep generation operating past planned retirement dates for the sake of system reliability. ■

NYISO News

NYISO Slightly Lowers Expected 2034 Shortfall

RENSSELAER, N.Y. — NYISO last week updated stakeholders on its draft *Reliability Needs Assessment*, which still shows an expected capacity shortfall by 2034, though it is slightly less than what was initially presented in July.

The ISO told the Transmission Planning Advisory Subcommittee on Sept. 3 that it had increased its assumption of special-case resource elections by about 200 MW. That resulted in a slightly lower loss-of-load expectation of 0.254 — still well above the required 0.1.

NYISO in July said it expected to be short by at least 1 GW, with an LOLE of 0.283, by 2034. (See *Prelim NYISO Analysis: 1-GW Shortfall by 2034*.)

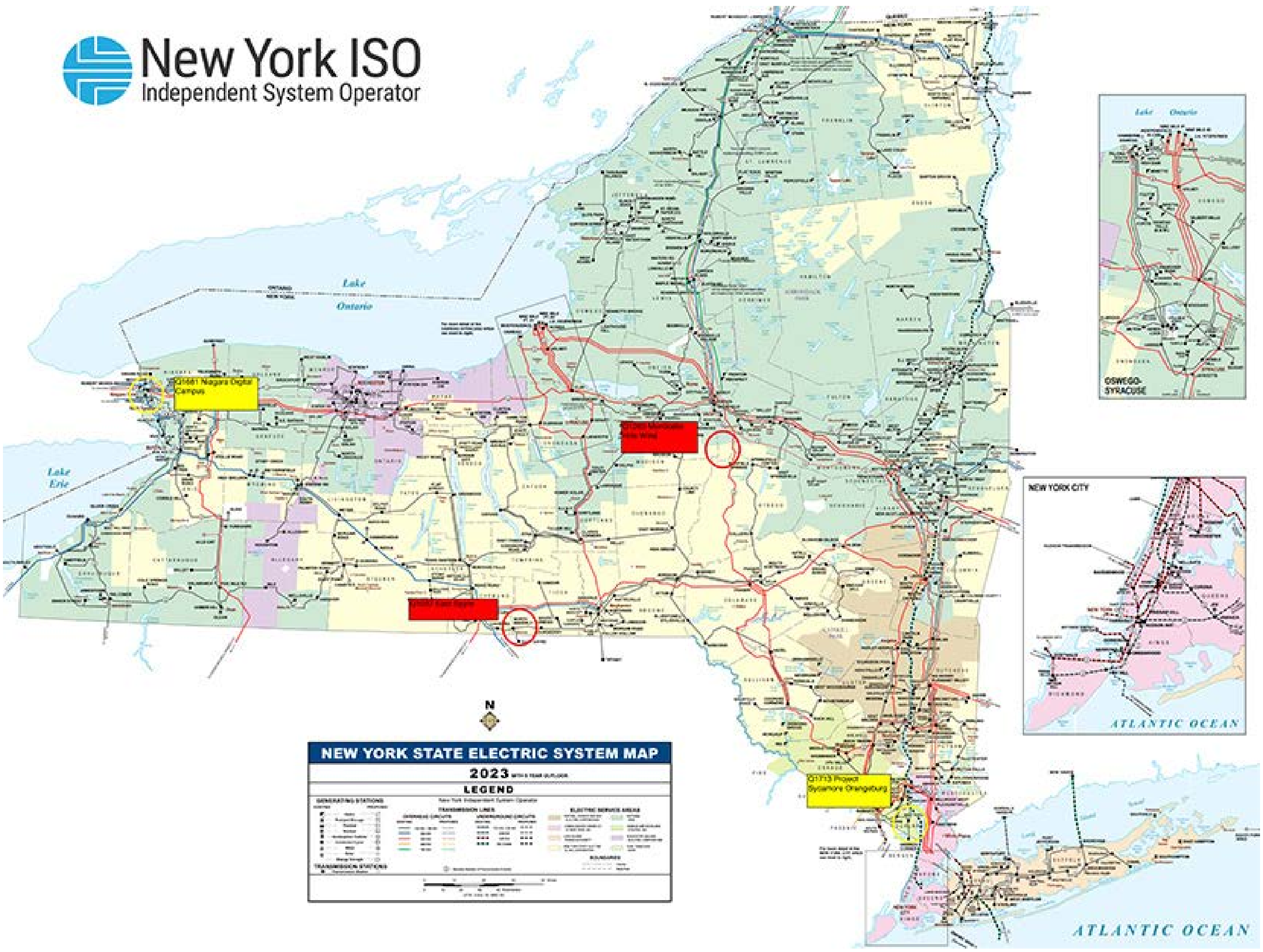
The ISO also revised down New York City's transmission security margin deficit, from 275 MW to 97 MW, by updating its load distribution model.

"We continue to see statewide resource deficiency by 2034," said Ross Altman, senior reliability manager for NYISO. "That is still driven by increasing demand, continued additions of large loads and unavailability of gas during winter peak conditions."

In response to a stakeholder question, Altman said NYISO estimates the statewide resource adequacy need to be about 800 MW, but it "could be as high as 1,875 MW" for transmission security. "It's very hard to put a number on it," he said.

The TPAS and Electric System Planning Working Group will review the draft RNA later this month. The Operating and Management committees are expected to vote on it next month, with a Board of Directors review and vote in November. ■

— Vincent Gabrielle



| NYISO

PJM News

PJM Stakeholders Voting on Hourly Reserve Notification Times

By Devin Leith-Yessian

PJM's Reserve Certainty Senior Task Force (RCSTF) is voting on a PJM *proposal* to add hourly differentiated notification times to the RTO's day-ahead (DA) energy market. (See "Hourly Notification Times," *PJM MRC/MC Briefs: Aug. 21, 2024*.)

During a Sept. 5 task force meeting, PJM's Joe Ciabattoni said generation notification times have become an important input for determining reserve eligibility, especially for offline, non-synchronized resources.

The vote is being *conducted* virtually through Sept. 12, with expedited endorsement sought at the Markets and Reliability Committee and Members Committee on Sept. 25. The tightened schedule would allow for the changes to become effective for the upcoming winter.

Hourly notification times can only be submitted in the real-time (RT) market, creating a discrepancy that Ciabattoni said can lead to units being assigned a DA reserve commitment that they cannot carry with their RT notification times.

Joel Romero Luna, senior analyst with the RTO's Independent Market Monitor, said the main use case for changing hourly notification times is to allow gas-fired generators to reflect pipeline restrictions that cause them to become less flexible. He said the Monitor has *guidelines* for how generators should use notification times to reflect gas nomination cycles, so there shouldn't be much variety in how notification times are used.

Joe Ciabattoni, PJM | © *RTO Insider LLC*

The change would require revisions to Manual 11: Energy & Ancillary Services Market Operations and Tariff Attachment K.

Rebecca Stadelmeyer, Gabel Associates' director of RTO services, suggested that the proposed language allowing hourly notification times used to commit non-synchronized and 30-minute reserves be consistent with references throughout Manual 11 and suggested replacing the 30-minute reserve with secondary reserves. Ciabattoni said PJM will consider the amendment.

Task Force Shifting to Long-term Work Areas

PJM's Danielle Croop said the RTO is not planning to rework a proposal to replace the 3,000-MW target for 30-minute reserve procurement with a formula that accounts for forecast peak loads and gas contingencies. Following the MRC's rejection of the package in July, stakeholders told PJM they were uncomfortable with the lack of tariff language to accompany the change. (See "Stakeholders Endorse Reserve Rework, Reject Procurement Flexibility," *PJM MRC Briefs: July 24, 2024*.)

Croop said PJM believes the status quo language allows the change by pointing to the manuals to determine the reliability requirement. In the absence of further direction from stakeholders, she said it is not clear how PJM should proceed.

Task Force Chair Lisa Morelli said in future meetings, the working group will pivot to its long-term work, which includes creating reserve product participation requirements and incentivizing resource flexibility. ■

PJM Asks FERC to Eliminate Energy Efficiency from Capacity Market

By Devin Leith-Yessian

Manu Asthana, PJM CEO | *© RTO Insider LLC*

PJM has filed governing document revisions that would remove energy efficiency from its Reliability Pricing Model (RPM), in line with stakeholder endorsement of an Independent Market Monitor proposal to eliminate EE from the capacity construct (*ER24-2995*).

The Monitor has argued EE can't participate as a capacity resource because the load reductions already are accounted for in PJM's load forecast and that capacity market revenues to program providers constitute an uplift payment with no corresponding reliability benefit.

Ahead of the Aug. 21 vote, EE providers argued the load forecast does not account for EE installations made possible by RPM revenues and that hastily moving to a vote to bar an entire resource class would curb consumers' ability to mitigate rising capacity costs. (See *PJM Stakeholders Endorse Elimination of EE Participation in Capacity Market*.)

The tariff and Reliability Assurance Agreement (RAA) revisions would come with a Nov. 6 effective date, which would preclude EE participation in the 2026/27 Base Residual Auction (BRA) set to begin Dec. 4.

"After years of experience, coupled with a careful review of what energy efficiency sellers have been including in their offers, it has become obvious to PJM, and a sector-weighted super majority of the PJM members, that the current paradigm is no longer appropriate," PJM wrote in the Sept. 6 filing. "Under the current framework, energy efficiency projects are compensated at the relevant RPM auction clearing price on the supply side even though energy efficiency capability has already been incorporated into the load forecast in aggregate and reduced the amount of capacity that needs to be procured in the RPM auction."

To avoid double counting the benefits of an EE installation — through both reduced capacity procurement and BRA revenues to the EE provider — PJM instituted the addback process in 2016, which removes EE that clears a capacity auction from the supply stack and increases the load forecast by a corresponding amount. Consumer advocates argued that undermines the ability for EE to displace capacity resources and drive clearing prices lower, while the Monitor argued it is an unnecessary uplift mechanism.

A proposal offered by the New Jersey Division of the Rate Counsel on Aug. 21 would have eliminated the addback with the aim of allowing EE to clear in capacity auctions akin to generation and demand response resources, while the *main motion* previously endorsed by the Market Implementation Committee would have tightened the measurement and verification (M&V) requirements and mandated a sole causal link between capacity market revenues and EE installations. Both were rejected before the Monitor proposal was endorsed.

In its filing, PJM wrote that state-mandated EE programs will continue to deliver benefits to consumers in the form of reduced capacity costs even in the absence of RPM revenues. Exelon sought *amendments* to the MRC proposals to add governing document language differentiating utility EE programs from third-party providers driven purely by PJM revenues.

"Energy efficiency projects will continue to receive economic benefits via reduced wholesale costs and the natural incentive of lower energy costs," the filing said. "There is simply no reason the same energy efficiency should be simultaneously compensated for capacity revenues based on the same underlying project that also receives a reduction in demand costs."

Petition Urges Technical Conference on EE

A group of EE trade groups and advocates jointly filed a petition with FERC urging it to open a technical conference on RTO rules around EE. Filing as the Alliance to Save Energy, the petition is signed by the American Council for an Energy-Efficient Economy, California Efficiency and Demand Management Council, Energy Efficiency Alliance of New Jersey, Institute for Market Transformation, Keystone Energy Efficiency Alliance, Metrus Energy, Midwest Energy Efficiency Alliance, National Association of Energy Service Companies and National Association of State Energy Officials.

The Aug. 29 petition states EE can effectively rise to the challenges posed by rising demand, the clean energy transition, transmission upgrades and backlogged interconnection queues in a manner that resources requiring long interconnection and construction lead times cannot (*AD24-12*).

"Energy efficiency offers significant advantages, including reducing the need for new generation and the costly transmission upgrades that come with it," the coalition wrote. "By lowering demand, it can also free up existing transmission capacity, enabling a more expedited interconnection of additional resources. Moreover, unlike other resources, energy efficiency can be implemented without depending on the interconnection queue, resulting in substantial time and cost savings."

PJM News

The rule changes proposed by PJM and several complaints filed by the Monitor and market participants go beyond one RTO to implicate EE across the nation, the coalition wrote. Acting without cross-RTO guidance from FERC since it accepted PJM's market design for EE in 2009 (*ER05-1410*), individual RTOs and their stakeholders have created a patchwork of market designs, the petition states.

"It is imperative that any changes to market rules affecting the participation and eligibility of EERs, which could jeopardize their role in these markets, stem from a thoughtful, holistic process led by the commission — not by one-off actions from individual RTOs," the petition says.

Four panels are envisioned as part of the technical conference, including:

- Energy Efficiency in Wholesale Markets Today, focusing on current market structures and models for EE participation.
- Reconciliation with Load Forecast, looking at how EE interacts with RTO load forecasts and whether market eligibility should be tied to inclusion in forecasts.
- Eligibility, Measurement, Verification and Standards, considering whether a causality principal should be an element of participation, as well as how capacity contributions can be quantified.
- Value Proposition of Energy Efficiency, focusing on EE compensation and its effectiveness as a supply resource.

American Efficient Pushes Back on Allegations of Tariff Violations

American Efficient is defending itself from accusations the company violated the PJM and MISO tariffs in the design of its mid- and upstream energy efficiency (EE) programs, which provide rebates to manufacturers, distributors and retailers for offering qualifying products (*EL24-113*).

The Independent Market Monitor has accused several EE market participants of not meeting the RPM participation requirements and has requested FERC prohibit future participation and require revenues be returned. The commission's Office of Enforcement (OE) also has opened an investigation into American Efficient specifically. (See *Monitor Alleges EE Resources Ineligible to Participate in PJM Capacity Market*.)

In its response to a 1b.19 notice from the OE — which notifies parties to an investigation that the office intends to recommend an administrative proceeding or civil action — American Efficient wrote that neither the Monitor's complaint nor the OE investigation had substantiated claims of fraud. While the open investigation is confidential, FERC publicly posted American Efficient's response to the 1b.19 notice, an executive summary of the response, a primer with background about the company and its request for a technical conference, and materials PJM submitted about the stakeholder process.

In the primer, American Efficient wrote that allegations that the company had engaged in fraud are unsubstantiated and the details of its program were reviewed and approved of by RTO staff.

"While the Market Monitors in PJM and MISO have strong policy preferences that EERs be removed from the markets, they are not arguing (nor could they, based on the record) that American Efficient misrepresented its program when seeking approval," the company wrote. "Instead, the allegations go directly to the fundamental features of American Efficient's EER program. There is no support for the allegation in the Preliminary Findings that American Efficient had a scheme with an intent to defraud the markets when the features were transparently presented to the RTOs, scrutinized by RTO staff, and subsequently approved.

"Put simply, an enforcement action based upon fundamental features of American Efficient's EER program that MISO and PJM knew and approved of would be inequitable."

In the executive summary, the company argued that PJM's statements in the stakeholder process that the tariff does not require a link between capacity market revenues and EE programs run against the OE's allegations. American Efficient said its PJM subsidiary Affirmed Energy followed the tariff as written and the OE is seeking to hold it to prospective rule changes.

"The plain text of the tariffs alone demonstrates that OE is wrong — EER providers are not required to pay end users, contract with end users, or prove that end users bought energy efficient products solely because of the provider's program," the company wrote. "Now that PJM has publicly stated its views about the tariff, affirming American Efficient's position and rejecting OE's position, that should conclusively settle the matter — OE has been wrong all along."

The materials PJM provided to the OE state the tariff interpretation the RTO offered throughout the stakeholder process is in contradiction with the OE's allegations.

"Through this process, PJM has clearly communicated in both verbal comments and public documents its view of the current rules — a view that is in direct contradiction to the Office of Enforcement's assertions about the requirements of PJM's tariff," the RTO wrote.

In its filing to eliminate EE, PJM again stated there is no requirement that there be a causal link between capacity market revenues under the status quo rules and EE programs and that it is seeking only to bar EE participation for future auctions.

"PJM seeks to apply the proposed market rule change on a prospective basis and is not proposing to unsettle RPM auction results or undo any existing energy efficiency resource commitment under the current tariff and RAA rules," PJM wrote. "The filed rate doctrine precludes retroactive changes for past actions where legal consequences have attached. As a result, energy efficiency resources that cleared the RPM Auctions for the 2025/2026 delivery year will need to follow through on their commitments and submit compliant post-installation measurement and verification plans in advance of that delivery year to substantiate their cleared quantities."

In its 1b.19 response, American Efficient also wrote that the OE is singling out the company for a "market-wide policy matter" that should be resolved by rule changes rather than enforcement actions. The company repeated recommendations that FERC hold a technical conference to discuss how EE participates in capacity markets, focusing on whether they should be a supply-side resource, how capacity contributions can be measured and verified, and the rules around ownership of capacity rights to EE savings.

In addition to the allegations made regarding its participation in PJM's capacity market, American Efficient wrote that MISO had found deficiencies in the capacity offered by its subsidiary Midcontinent Energy following an audit in 2021. While the company disputed the filing, Midcontinent opted to not seek to offer capacity in MISO's market once the OE had supplied notice of its investigation.

A second complaint seeks the elimination of EE from the RPM and argues that the add-back violates PJM's tariff — a position also taken in a complaint the New Jersey, Maryland and Illinois consumer advocates filed. A complaint submitted by CPower alleges PJM overstepped in issuing guidance ahead of the 2025/26 BRA that tightened the auction participation requirements, substantially curtailing EE participation. ■

SPP News

‘Leaning’ Evident in BPA Response to NW Senators

Letter from Administrator Hairston Emphasizes Governance, Markets+ Benefits

By Robert Mullin

BPA Administrator John Hairston | *Bonneville Power Administration*

CAISO’s adoption of the West-Wide Governance Pathways Initiative’s “Step 1” changes won’t overcome the Bonneville Power Administration’s objections to the governance of the ISO’s Extended Day-Ahead Market (EDAM), BPA Administrator John Hairston told U.S. senators from the Pacific Northwest.

“Our specific concern is that, with only Step 1 in place, the market governance remains under the ultimate authority of California,” Hairston *wrote* in an Aug. 21 letter to the senators, which has not yet been posted on the agency’s website.

Hairston’s comments were part of a broader response to a series of questions posed to him in a July 25 letter signed by Democratic Sens. Jeff Merkley (Ore.), Ron Wyden (Ore.), Maria Cantwell (Wash.) and Patty Murray (Wash.).

In their letter, the senators urged the agency to “act carefully and deliberately” before selecting a day-ahead market and to delay a “draft letter to the region” relaying its decision, previously slated for Aug. 29, until more developments play out around EDAM and SPP’s competing Markets+ offering. (See *NW Senators Urge BPA to Delay Day-ahead Market Decision*.)

The senators’ letter signaled a preference shared by many Western state officials, public interest groups and large energy users — and some utilities — that the region will benefit most from a single organized electricity market that includes CAISO.

It also expressed concern that BPA staff in April issued a “leaning” recommending the agency choose Markets+ over EDAM, citing the SPP market’s independent governance and overall design as primary factors supporting the opinion. The senators directed the agency to answer 14 detailed questions to clarify the reasons behind the leaning. (See *BPA Staff Recommends Markets+ over EDAM*.)

Inadvertently or not, the senators got one wish: In his Aug. 21 response, Hairston said BPA would be delaying its market decision until next year, an announcement it would later relay to its stakeholders on Aug. 25, saying both markets have “outstanding issues that require additional analysis.” (See *BPA Postpones Day-ahead Market Decision Until 2025*.)

But Hairston’s Aug. 21 response to the senators clearly — and understandably — shows the fingerprints of the staff that produced the leaning. It also evinces continued concerns among some parties in both the Northwest and Southwest about a market arrangement that could be dominated by California and its interests.

In response to the senators’ question about which market BPA expects “will provide the greatest improvement in grid reliability in the Northwest,” Hairston cites the benefit of the Markets+ requirement that its participating entities also participate in the Western Power Pool’s Western Resource Adequacy Program (WRAP).

“The EDAM proposal’s lack of a common resource adequacy metric makes it difficult to assess whether the market or its participants will be resource adequate in the planning horizon for the market,” Hairston wrote, adding that California’s “state-mandated” RA metrics don’t align with WRAP requirements and that EDAM will accept non-California participants that haven’t committed to the WRAP.

Responding to another question about which market would do more to reduce greenhouse gas emissions from the Northwest’s electricity sector, Hairston said Markets+ has made progress in developing GHG tracking and accounting procedures that would allow BPA’s customer base of publicly owned utilities to meet Washington’s cap-and-invest program obligations and Oregon’s “non-pricing” carbon requirements.

“Our continuing concern with CAISO’s EDAM design is that California is able to deem a disproportionate share of carbon-free market-traded resources as delivered to California, to the disadvantage of utilities in the Northwest and their ability to meet their state goals,” he wrote.

Addressing a question about the impact on the Northwest grid from “seams” between two different markets, Hairston cited BPA’s previous experience using the Coordinated Transmission Agreement with CAISO to enable several of the region’s utilities to use BPA’s transmission system to participate in the ISO’s Western Energy Imbalance Market before the agency itself joined that market.

“Bonneville expects to undertake a similar exercise if necessary to manage day-ahead market seams,” he said.

Governance Still Key

But the issue of CAISO’s state-run governance was front and center in Hairston’s response to the senators — just as in the staff leaning.

“Bonneville seeks to participate in a market that has a durable, effective and independent governance structure [that] provides fair representation to all market participants and stakeholders,” he wrote.

Hairston described the choice as being between Markets+, with its independent board of directors, and EDAM, which would fall under the “shared authority” of the Western Energy Markets (WEM) Governing Body and the ISO Board of Governors “appointed by the governor of California.”

Hairston acknowledged the progress made by the Pathways Initiative in forcing movement on CAISO’s governance. The ISO and WEM boards last month voted to approve the Pathways plan giving WEM officials “primary authority” over WEIM- and EDAM-related market-rule decisions. (See *CAISO, WEM Boards Approve Pathways ‘Step 1’ Plan*.)

But his response to the senators’ question about that effort illustrated his skepticism around whether the “Step 2” plan for advancing a California bill to grant the WEM Governing Body “sole authority” over the EDAM would get traction or meet BPA’s requirements.

“While we appreciate the Pathways’ sponsors optimism for a positive outcome, such efforts have repeatedly failed to secure legislative approval. It also remains to be determined what legislative conditions and constraints will continue to impede an independent governance structure,” he wrote.

Pathways backers expect to begin working with California lawmakers on a bill this fall after the conclusion of the current session. They hope to get the bill introduced and passed during the 2025 session, which starts in January.

That bill might not progress in alignment with BPA’s new day-ahead market decision timeline. The agency now plans to release its draft decision in March 2025, followed by a final decision in May. ■

SPP News

SPP Adds Advisory Committee for Resource Adequacy

REAL Team Pauses SAWG's Work on Demand Response

By Tom Kleckner

DALLAS — Now that SPP has set planning reserve margins for the 2026 summer and 2026/27 winter seasons, the grid operator has turned its attention to setting up a longer-term PRM.

"We've got to get that done so that we can help our members better prepare for what's coming," COO Lanny Nickell said during a recent Resource Energy and Adequacy Leadership (REAL) Team meeting.

Referring to comments made by SPP Board Chair John Cupparo after the directors approved the PRMs despite stakeholder pushback, Nickell said he's received support for a governing structure to advise staff and ensure upcoming resource adequacy work is coordinated. (See *SPP Board of Directors/RSC Briefs: Aug. 5-6, 2024*.)

During the August board meeting, Cupparo told directors and stakeholders it appeared necessary to establish the longer-term PRM with "defined mechanisms" to assess and adjust the reserve margin at a "reasonable" interval. He also mentioned implementing regional load forecasting capabilities; strengthening SPP's roles in bringing generation online faster and building transmission; and continuing to develop outward communication "to those who rely on us" and who can help in the infrastructure build.

"All of these items have either been proposed or are in flight," Cupparo said in August. "The question is whether some or all should be under a single program management structure with a single point of oversight to ensure we get the necessary outcomes in a timely manner. This is a big ask, but we are facing a generational challenge."

Working with the board, Nickell drew up a senior-level steering committee to perform that task. He said the group will deliver an action plan or project plan to SPP's board and state commissioners' committee in October. It then will oversee the work and "make sure it happens," Nickell said, noting he sees the group as filling an advisory role and not circumventing the stakeholder process.

The committee is composed of REAL Team Chair Kristie Fiegen, who also chairs the South Dakota Public Utilities Commission — "Congratulations, Kristie," Nickell said as he read

Evergy's Denise Buffington makes her point as SPP COO Lanny Nickell listens during a recent REAL Team meeting. | *© RTO Insider LLC*

off the names — the Markets and Operations Policy Committee chair; ITC Holdings' Alan Myers and then Omaha Public Power District's Joe Lang in 2025; Cupparo as the Strategic Planning Committee's chair; and Nickell as SPP's executive sponsor.

"How do we make sure all of this stuff happens in a timely manner?" Nickell asked rhetorically. "It kind of boils down to prioritization and actuation. How do we generate the ideas? How do we make sure those ideas are actually executed in a timely fashion? We've got to have more generation, we've got to have more transmission, and we need it faster."

He addressed stakeholders nervous about being able to meet future PRM increases, saying it can be challenging to "move the needle in a big way in the stakeholder environment we're in."

"That'll be part of our challenge," Nickell said. "We're going to continue to rely on the stakeholder groups. This steering committee is not a solution committee, right? We're not coming up with the answers. We just need to make sure that answers are being developed in a timely fashion."

Demand Response RR Paused

The REAL Team had only one voting item during the Aug. 21 meeting, unanimously agreeing to direct the Supply Adequacy Working Group to pause its early work on a tariff change related to demand response. The team said it will determine a path forward to a holistic solution.

Texas Public Utility Commission staffer Shawnee Claiborn-Pinto abstained from the vote.

The SAWG had been working on a revision request (*RR618*) intended to accurately account for potential increases in demand-response loads claimed by load-responsible entities (LREs) to satisfy their resource adequacy requirement. The change includes a performance mechanism to accurately accredit DR programs based on their performance.

Chris Haley, SPP | *© RTO Insider LLC*

SPP's Chris Haley said the SAWG had made progress on the policy package but hit a roadblock after it began receiving load projections from LREs as part of a survey of 2029 resource plans.

"This is going to send a (five-year) signal, but there's a lot of moving pieces here. It was kind of shocking for us, at least when we saw the amount of load growth that's being projected for 2029 from the '23 to '24 submittals," he said. "Some of that roadblock was around the ability to have market oversight, or ops oversight and insight into these programs. There was some pushback on doing full market registration for demand response that was being submitted for resource adequacy. There is some demand response in the market today, but right now, that demand response is not being submitted for resource advocacy. It is purely a market product today."

"Regardless of what we do with [DR's] Phase 1, I think our very next step is to better understand the magnitude of the potential operations issue," SPP's Natasha Henderson said. "Resource adequacy is long-term planning. It's based upon a lot of different information and it's a good guess, right? In my mind, I think we just shouldn't lose sight of the fact that we need to keep the lights on in real time, and I think we need some agreement on what that is, what that means for demand response."

The resource plans indicate a net increase of about 3,000 MW of installed generation by 2029, much of it thermal. That is balanced out by a 3,000-MW increase in forecasted peak demands.

The SAWG expects to bring a recommended long-term PRM to the REAL Team's November meeting. ■

Company Briefs

Navisun, Ampion Partner on Community Solar in 4 States

Ampion, a community solar subscription management company, and Navisun, an independent power producer, last week announced they have entered a partnership to construct solar projects in the Northeast and Midwest.

The plan is for Navisun to design, construct, own and operate five community solar projects in Maine, Massachusetts, New Jersey and Illinois, while Ampion handles subscriber acquisition, billing, customer care and long-term subscription management.

The projects are expected to produce more than 21 MW.

More: *pv magazine*

Samsung SDI Unveils New Battery Solutions at Energy Expo

Samsung SDI this week showcased its latest energy storage system battery solutions at Renewable Energy Plus 2024, a North America renewable energy exhibition.

The battery maker introduced its Samsung Battery Box 1.5, a containerized system featuring improved density and an enhanced fire suppression system. Samsung also presented a high-output battery for uninterruptible supply systems, set for mass production next year.

More: *AJP*

Federal Briefs

Groups, Residents File Petitions Against LNG Terminal

Environmental groups and residents last week filed two petitions asking the U.S. Court of Appeals for the D.C. Circuit to reject the June decision by FERC approving the proposed $10 billion Calcasieu Pass 2 terminal in Louisiana.

Since FERC approved the project, the court in separate cases has remanded or vacated the commission's approval of the Rio Grande, Texas and Commonwealth LNG facilities. In rejecting the terminals, the court cited inadequate review of their impacts on environmental justice, greenhouse gas emissions, air pollution and other factors.

More: *Floodlight*

US Solar Industry Installs 9.4 GW of New Capacity in Q2

The U.S. solar industry installed 9.4 GW of new generation capacity in the second quarter of this year, according to a report released by the Solar Energy Industries Association and Wood Mackenzie.

Texas leads the nation with 5.5 GW of capacity installed in the first half of 2024.

By 2029, the nation's total solar capacity is expected to double to 440 GW.

More: *Solar Power World*

BOEM Finalizes Gulf of Maine Environmental Review

The Bureau of Ocean Energy Management last week released its final Environmental Assessment of the Wind Energy Area located in the Gulf of Maine.

BOEM found that leasing and site assessment and characterization activities will not have a significant impact on the environment.

In April, the Department of the Interior announced a proposed offshore wind energy lease sale in the Gulf of Maine, which would include eight potential leasing areas. The areas total nearly one million acres and have the potential to generate 15 GW.

More: *North American Windpower*

Trump Vows to Pull Back IRA's Unspent Dollars

Donald Trump last week said he would rescind any "unspent" funds under the Inflation Reduction Act should he be elected president in November.

Trump did not specify which IRA programs he would target.

Analysis from April found that of the $145 billion in direct spending on energy and climate programs in the IRA, the Biden administration had announced roughly $60 billion in tentative funding decisions.

More: *POLITICO*

State Briefs

ARIZONA

AG Challenges Power Plant's Exemption from Review

Attorney General Kris Mayes and two environmental groups filed lawsuits challenging the Corporation Commission's decision to exempt a 200-MW power plant expansion from environmental review.

In June, the commission voted to overturn a ruling by the Power Plant and Line Siting Committee that required UniSource Energy to obtain a certificate of environmental compatibility for the expansion of its existing gas plant in Mohave County. The committee had voted 9-2 to deny UniSource's attempt to exempt the Black Mountain expansion from review, citing a state law that requires utilities to obtain a certificate of environmental compatibility before building plants larger than 100 MW. However, the commission found that because the project will be made up of four individual 50-MW units, that law does not apply.

The Sierra Club, Western Resource Advocates and Adam Stafford, an assistant attorney general who chairs the line siting committee, all asked the commission to reconsider the case. Those requests were ignored, prompting Mayes and the groups to challenge the ruling in Maricopa County Superior Court.

More: *KJZZ*

Tucson Electric Power Tx Line OK'd by Corporation Commission

The Corporation Commission last week unanimously approved a Tucson Electric Power high-voltage transmission line.

While TEP hopes to complete the line by summer 2027, it will first have to get special exceptions from the city to build the project above ground. The company has 10 weeks to apply for the special exception. If it is not granted, the city and utility will have six months from the approval to find an alternative funding source for undergrounding portions of the line that does not increase rates for customers.

More: *Tucson.com*

CALIFORNIA

Fire Breaks Out in Escondido SDG&E Battery Storage Facility

A fire broke out last week at a San Diego Gas and Electric-operated battery storage facility in Escondido.

Upon arrival, fire crews noticed smoke coming from one of the battery storage trailers. Technicians confirmed a small fire was burning in one of the lithium-ion batteries. Experts said water cannot be put on the fire because of the involved chemicals.

More: *KUSI*

GEORGIA

Georgia Power Plans Energy Storage at Plant Hammond Site

Georgia Power in late August announced it will build a 57.5-MW storage system at its decommissioned Plant Hammond site.

The Tesla Megapack 2 Xl is part of the company's plan to add 500 MW of capacity statewide.

The Public Service Commission has approved the battery-storage component of the plan but must certify the four BESS projects.

More: *Rome News-Tribune*

Houston County Rejects Solar Farm

The Houston County Board of Commissioners last week voted unanimously to disapprove a rezoning request for a $300 million solar project.

Silicon Ranch, the project developer, had asked the county to grant an exception so it could install solar panels on parts of 4,600 acres zoned for agriculture.

The SR Robins project would have been one of the largest solar installations in the state.

More: *The Atlanta-Journal Constitution*

PSC Approves Georgia Power Rate Rollback

The Public Service Commission last week approved Georgia Power's request to reduce customer rates by $122 million to reflect the utility's savings from corporate tax cuts the General Assembly enacted this year.

The PSC required the utility in its 2022 rate case to pass any savings from future tax cuts to customers.

The reduction, which will save the average residential customer $2.25 a month, will take effect Jan. 1.

More: *Capitol Beat*

INDIANA

AES Submits Request for Dubois County Solar Project

AES Indiana in late August submitted a request to the Utility Regulatory Commission to buy a new solar project being built in Dubois County.

The solar field, which is expected to be completed in 2027, will provide 85 MW. There will also be a storage component.

AES is seeking to construct and acquire the project though a Certificate of Public Convenience and Necessity.

More: *Inside Indiana Business*

MARYLAND

Investigation: Reports of Gas Odor Night Before Bel Air Home Explosion

The National Safety and Transportation Board last week released a preliminary report that found reports of gas odors were made the night before a deadly Aug. 11 home explosion in Bel Air.

The report noted that gas and electrical lines were in proximity in a common trench, similar to what led state regulators to penalize Baltimore Gas and Electric more than $437,000 for safety violations that caused a 2019 explosion in Columbia. The report on the Bel Air explosion said BGE investigators recovered damaged electrical lines and a gas service line with a hole on the bottom and detected underground gas around the destroyed home.

The report also stated that the night before the explosion, the home experienced an electrical outage. The outage prompted a BGE technician to respond to the scene, with two reports of the smell of gas later being made.

More: *Capital Gazette*

MISSISSIPPI

Entergy to Build First Natural Gas Plant in 50 Years

Entergy Mississippi last week announced it will build a new natural gas power station in Greenville.

The company said it plans to retire the Gerald Andrus Steam Electric Station and replace it with a natural gas plant. It would be the first such plant the company has built in 50 years.

The plant is expected to be operational in 2028.

More: *Magnolia Tribune*

NEW JERSEY

Leading Light Wind Asks BPU for Pause on OSW Construction

Leading Light Wind (LLW) has asked the Board of Public Utilities for a pause through late December on its plan to build an offshore wind farm off Long Beach Island.

In a filing with the board made in July, the company said it has had difficulty securing a manufacturer for turbine blades and is currently without a supplier. LLW asked for a pause through Dec. 20 while a new source is sought.

The project would be built 40 miles off Long Beach Island and would consist of up to 100 turbines.

More: *WHYY*

VIRGINIA

Hydro-Quebec's EVLO to Install 300 MW of Batteries

Canadian battery energy storage systems (BESS) provider EVLO Energy Storage, a subsidiary of Hydro-Quebec, last week said it will deploy more than 300 MW in BESS projects in the state.

Plans include three EVLOFLEX systems, scheduled for commissioning in 2025 and 2026. The first project will be 5-MW and will be part of a facility microgrid powered by solar and battery storage. The second project will be a 75-MWh standalone storage system, while the third project will install 225 MW at a solar project located at a transportation hub.

More: *Renewables Now*

Youngkin Appoints 2 to Environmental Justice Council

Gov. Glenn Youngkin recently appointed Hope Cupit and Eureka Tyree to the state's Council on Environmental Justice.

Cupit is a former Air Pollution Control Board member, while Tyree is the vice chair of the Cumberland County Board of Supervisors.

Aimed at raising awareness of minority, low-income, tribal and other communities, the council was created by former Gov. Terry McAuliffe.

More: *Virginia Mercury*

WYOMING

Supreme Court Sides with Small-scale Solar Users

The Wyoming Supreme Court on Aug. 30 affirmed a state law that incentivizes net-metering.

The court said the Public Service Commission erred when it approved a request by High Plains Power to shift from an annual to a monthly compensation scheme with customers who intermittently contribute their excess solar-generated electricity back to the utility. The court rejected High Plains Power's plan to compensate solar users for their excess power at a monthly wholesale rate rather than the higher retail rate.

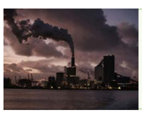
The PSC must now reconsider the monthly tariff it approved for High Plains and potentially two other co-ops that were not part of the lawsuit.

More: *WyoFile*

National/Federal news from our other channels

Clean Power Installations Hit Record for Second Quarter, ACP Says — NetZero Insider

DOE Set to Fund 2 Energy Storage Research Hubs — NetZero Insider



DC Circuit Strikes down Emissions Standards for 'New' Pre-2020 Boilers — NetZero Insider

NERC, Industry Discuss IBR Issues in Technical Conference — ERO Insider

NPCC, NYSEG Agree to Settle Control Center Violation Federal/National — ERO Insider

Northeast news from our other channels

NY Takes a Closer Look at Advanced Nuclear — NetZero Insider

Multistate Offshore Wind Solicitation Lands 2,878 MW for Mass., RI — NetZero Insider

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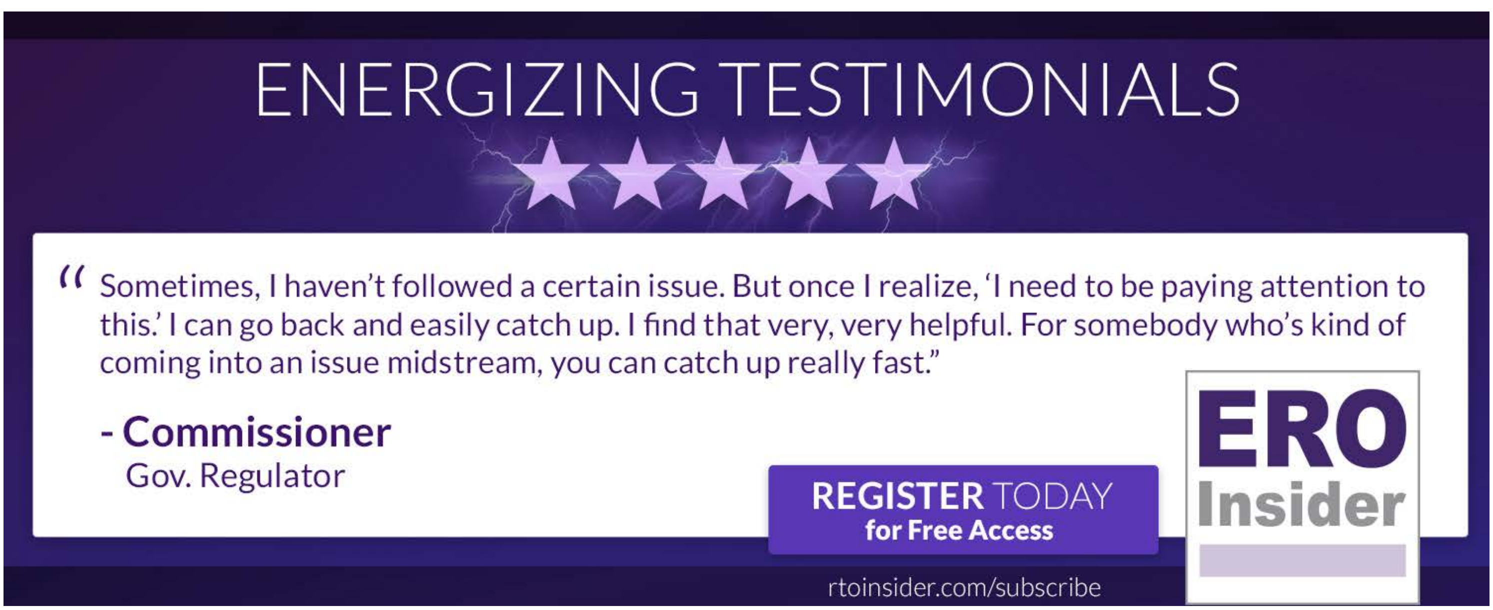
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